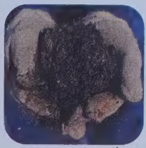
2001 ANNUAL REP

RECOGNIZE

the energy difference

GROWTH

RESOURCES



PROFITABILITY

INTEGRATION

SUSTAINABILITY

SUNCOR ENERGY

RECOGNIZE

Suncor Energy Inc.

In 1967, we led the world in tapping the first commercial barrel of crude from the Athabasca oil sands. Today, we continue that pioneering tradition with an integrated strategy that is recognized as uniquely Suncor.

Our strategy levers expertise from mining to refining, to strengthen a core business built around the same oil sands foundation we launched 35 years ago.

In 2001, Suncor took a giant step forward with the commissioning of a $3.4 billion expansion of our oil sands operation, increasing production capacity to 225,000 barrels per day. In the same year we announced long-term plans to further boost production capacity up to 550,000 barrels of oil per day, fuelled in part by Suncor natural gas, with products marketed through Suncor distribution channels.

We power it; we produce it; we market it. Recognize the energy difference.

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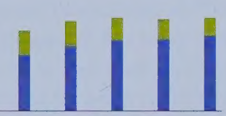
This annual report contains forward-looking statements based on current expectations, but which involve risks and uncertainties. Actual results may differ materially. See page 44 for additional information. All financial information is reported in Canadian dollars unless noted otherwise.

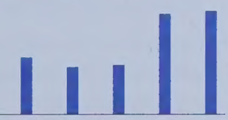
The steady increase in our share price over the past decade is a reflection of Suncor's growing oil production and expanding earnings and cash flow. Most of all, it is a reflection of investor confidence in Suncor's ability to generate high returns.

Production
(thousands of barrels of oil equivalent per day)



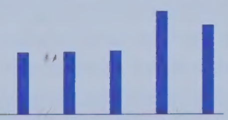
	1997	1998	1999	2000	**2001**
Natural Gas	40.0	41.2	37.7	33.3	**29.5**
Crude Oil and Natural Gas Liquids	95.1	109.9	119.0	121.1	**127.1**
Total	135.1	151.1	156.7	154.4	**156.6**

Net Earnings
(Cdn$ millions)



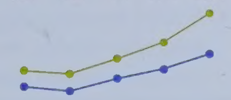
1997	1998	1999	2000	**2001**
214	178	186	377	**388**

Cash Flow from Operations
(Cdn$ millions)



1997	1998	1999	2000	**2001**
575	580	591	958	**831**

Share Price
($ per share as of December 31)



	1997	1998	1999	2000	**2001**
Share Price TSE (Cdn$)	24.50	23.00	30.20	38.30	**52.40**
Share Price NYSE (US$)	17.05	14.95	20.90	25.70	**32.94**

recognize our

GOALS

Each of Suncor's businesses supports an overall goal of being a low-cost, reliable and highly profitable oil sands producer well positioned for sustainable growth.

2001 milestones

- Project Millennium, a four-year, $3.4 billion expansion project was commissioned on schedule, nearly doubling Suncor's Oil Sands production capacity to 225,000 barrels of oil per day.
- Expansion at Oil Sands contributed to a company-wide production average of 156,600 barrels of oil equivalent per day.
- Growth continued to be a priority, as the company initiated construction of the Firebag In-situ Oil Sands Project. Suncor also took the first steps to gain regulatory approval for Voyageur – an expansion planned to increase production up to 550,000 barrels per day by 2010 to 2012.
- Suncor's Natural Gas business exceeded goals for production volumes, return on capital employed and cost reductions, advanced its coalbed methane strategy and launched Prospect Generation Services, a potential future revenue stream.
- The Sunoco division of Energy Marketing and Refining increased its share of the Ontario refined product market to 18%, up 1% from 2000.
- Electricity was generated from Suncor's first renewable energy project, the SunBridge Wind Power Project, a partnership with Enbridge Inc.

2002 plans

- Increase Oil Sands production to an average 210,000 barrels of oil per day and fully integrate Project Millennium with the base operation.
- Increase emphasis on operational excellence and tighter cost management to reduce cash operating costs at Oil Sands to $10 to $10.50 per barrel (US$6.50 to $6.80).
- By year-end, submit to regulators a development application for Voyageur that describes the company's plans to increase production capacity up to 550,000 barrels per day by 2010 to 2012.
- Increase Natural Gas production volumes to 180 to 190 million cubic feet per day to outpace growing internal energy demands and deliver a return on capital employed in excess of 12% at mid-cycle pricing levels.
- Improve gross profit performance at Suncor's Sarnia refinery to become one of the top third ranked refineries of comparable size in North America.
- Aggressively pursue safety and occupational health as a key element of operational excellence with a vision of achieving zero injuries to our workforce.
- Invest further in wind power projects and carbon capture technologies. Continue to pursue greenhouse gas offsets and energy efficiency to reduce emissions per unit production.

financial

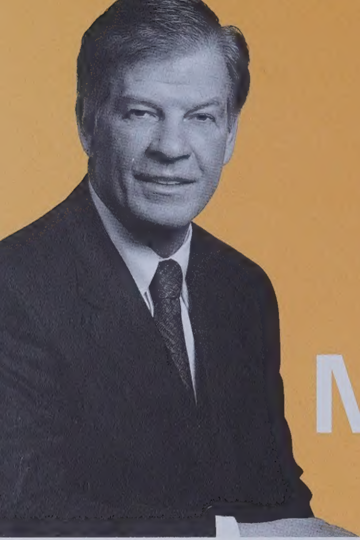
HIGHLIGHTS

Year ended December 31 (Cdn$ millions)	**2001**	2000	1999	1998	1997
Financial					
Revenues	**3 995**	3 388	2 387	2 070	2 154
Operational earnings [1]	**433**	414	167	175	214
Net earnings	**388**	377	186	178	214
Operational cash flow [1]	**1 061**	1 009	591	580	575
Cash flow from operations	**831**	958	591	580	575
Capital and exploration expenditures	**1 678**	1 998	1 350	936	847
Total assets	**8 094**	6 833	5 176	4 104	3 457
Net debt	**3 143**	2 236	1 334	1 289	767
Dollars per Common Share					
Net earnings [2]	**1.63**	1.58	0.74	0.81	0.98
Cash flow from operations [2]	**3.52**	4.11	2.51	2.64	2.62
Cash dividends	**0.34**	0.34	0.34	0.34	0.34
Key Ratios – %					
Return on capital employed	**17.9**	16.6	8.3	9.5	14.3
Return on shareholders' equity	**14.8**	16.5	10.3	12.3	16.2
Debt/debt plus shareholders' equity	**53.1**	47.7	38.9	46.7	36.8
Net debt/cash flow from operations (times)	**3.8**	2.3	2.3	2.2	1.4

[1] See note ** on page 23 regarding operational earnings and operational cash flow.

[2] Per share amounts for earnings and cash flow from operations are after deducting dividends on preferred securities issued in 1999.

Suncor's products are sold to customers in Canada and the United States.



MESSAGE

to shareholders

visionary. challenging. memorable.

All three words have been used to describe the year that Suncor experienced in 2001 – a year that ended so very differently from how it began. A landmark year in our company's history. A year in which we recognized the 'energy difference' that makes Suncor's story unique.

Suncor realized significant accomplishments in 2001. Record-breaking production and earnings, initiating construction of a commercial scale in-situ oil sands operation and developing our first wind power project. But it was the completion of Project Millennium – a four-year, $3.4 billion project – that made 2001 so remarkable.

Project Millennium was an unprecedented achievement involving all the vision, creativity, technical expertise and plain hard work we could bring to bear. This tremendous undertaking has effectively doubled our Oil Sands production capacity to 225,000 barrels per day. Over the longer term, Millennium will serve as a foundation for the future growth of our company as we progress our plan to double production again in the decade ahead and become one of the lowest cost oil producers in North America.

Building on the momentum of Millennium, we announced plans in late 2001 for Project Voyageur. Like the voyageurs of Canadian history, Suncor has a record of forging new paths in the energy industry and we look to the journey ahead of us with confidence. Voyageur's ultimate goal is to increase Oil Sands production capacity up to 550,000 barrels per day by 2010 to 2012.

While we recognize 2001 as a year of accomplishment, we also realize there is more work to be done to strengthen our business. Going forward, rapid growth must be very carefully managed to protect profitability. This is especially true in the oil sands industry, where rising labour and construction costs have driven up capital costs for all producers. For Suncor, rising cost pressures resulted in a cost increase of approximately $1.4 billion from when Project Millennium was announced in July 1997 to its commissioning in December 2001.

We believe we can better manage future costs by taking direct control of key elements of expansion and controlling the scale of growth projects. To do this, we've created our own Major Projects team for directly managing engineering, procurement and construction, providing tighter control for new capital projects. And we've structured future projects in stages to reduce the pressure on the workforce and area infrastructure.

"Project Millennium was an unprecedented achievement involving all the vision, creativity, technical expertise and plain hard work we could bring to bear."

Rick George
President and Chief Executive Officer

highlights

In 2001 we increased production capacity of our Oil Sands business by more than 100,000 barrels per day, reached a record stock market capitalization of $11 billion and outlined plans for continued dramatic growth throughout the decade.

Through these 12 months, change has been constant and our employees must be recognized for the exceptional focus that enabled Suncor to reach the milestones we did this year.

In addition to completing Project Millennium on schedule, Suncor launched the Firebag In-situ Oil Sands Project, a key stepping-stone to realizing our plans for Voyageur. Firebag moves Suncor into in-situ production of oil sands reserves that are too deeply buried for open-pit mining. Instead, we'll drill horizontally into the pay zone and use pairs of parallel wells to inject steam into the formation, allowing us to pump the bitumen to the surface for upgrading.

The first stage of Firebag, when combined with construction of an associated vacuum tower to process sour crude, is expected to increase production to 260,000 barrels per day in 2005 at a total capital cost of about $1 billion. Subject to approval of Suncor's Board of Directors, three additional stages could increase production at Firebag up to a total of 140,000 barrels of bitumen per day by the end of the decade.

To progress these and other projects, we announced capital spending plans of $900 million for 2002, with about two-thirds of that sum directed to our Oil Sands operations. This spending plan supports continued strong growth, while giving Oil Sands a breather from the more than $3 billion in capital projects we undertook during the past two years. Reduced capital spending also provides Suncor the opportunity to direct cash flow to debt reduction.

Also in 2001, Suncor sold its interest in the Stuart Oil Shale Project in Australia. While we believe the project has potential, we had to make a choice among competing growth priorities. For Suncor it makes sense to focus our people and resources on our core businesses in Canada.

financial performance

Financial performance in 2001 was comparable to the previous year, with net earnings of $388 million, up from $377 million in 2000. Financial results were strong primarily as a result of record-breaking production at Oil Sands, which averaged 123,200 barrels of oil per day.

Earnings for Suncor's Natural Gas business were $117 million, compared with $98 million a year ago. At Sunoco, a business we now refer to as Energy Marketing and Refining, refining margins were lower while retail margins remained even, holding earnings steady at $80 million, compared to $81 million in 2000.

Suncor, like the rest of the oil and gas industry, saw its financial results impacted by the decline in commodity prices. Halfway through 2001 crude oil and natural gas prices gave way to weakening demand and higher inventories as the economy slowed.

Overall, we began 2002 with greatly increased Oil Sands production and a clear investment plan for continued profitable growth in all our businesses.

the energy difference

As I meet with investors across Canada and around the world to tell the Suncor story, it's becoming clear that people are recognizing the energy difference we deliver. Achievements during 2001 highlight the five characteristics of Suncor's energy difference:

Growth

Millennium, Firebag and the larger Voyageur plan are on course to take Oil Sands average production from 123,200 barrels per day in 2001 to 210,000 barrels per day in 2002 and up to 550,000 barrels per day in 10 years. Continued growth provides effective insulation from commodity price erosion throughout economic cycles. And the addition of new, stand-alone facilities gives us greater flexibility to maintain production and revenue generation from one processing line while the other undergoes maintenance.

Resources

Suncor has assembled oil sands leases containing more than 12 billion barrels of recoverable resources, as evaluated by independent analysts. On these leases there are no finding costs and on our mining leases you can "discover" oil with the toe of your boot in many places. And there's no exposure to the unpredictable decline rates of conventional reserves. Instead, there is a huge, well-defined resource base that can be continuously developed with a relatively predictable long-term production rate.

Profitability

Since 1992, we've reduced cash operating costs of oil production from about $17 per barrel to around $11.90 (US$8) per barrel and we're working on further reducing costs through economies of scale, debottlenecking and operational efficiencies. Our vision is to continue to move down the cost curve to $8.50 to $9.50 (approximately US$6) per barrel to become one of the lowest cost oil producers in North America.

Integration

Suncor defines successful integration by its ability to support the profitable growth of Oil Sands. Our Natural Gas business reduces Suncor's exposure to volatile natural gas prices by ensuring we have enough production to offset internal demand. And our Energy Marketing and Refining business helps provide market stability for Oil Sands products. Both businesses also benefit Suncor through diversity of products, customer base and revenue streams.

Sustainability

We recognize that business success is not sustainable through strong financial performance alone. To maintain success over the longer term, companies must also support environmental and social objectives. This kind of responsible action provides a competitive advantage.

At Suncor, we develop hydrocarbon energy responsibly for today's needs while also investing in renewable energy to meet what we believe will be a growing future demand. That's why we plan to invest $100 million in renewable energy projects by 2005. In the past two years we've examined a variety of project options, investing over $16 million. In August 2001 the SunBridge Wind Power Project in southwestern Saskatchewan, a partnership with Enbridge Inc., connected the first renewable electricity to the power grid in that province.

Also during 2001 we advanced our plans to reduce greenhouse gas emissions and supported Canada's national climate change efforts through increased energy efficiency, carbon capture research and emissions trading initiatives.

priorities for 2002

With Project Millennium completed, Suncor can focus on getting back to basics in 2002. We'll centre our attention on strengthening our business by delivering steady, reliable production, reducing operating costs and promoting a safe workplace and healthy environment.

Our goal for 2002 is to increase Oil Sands production to a daily average of 210,000 barrels per day. When combined with production from our Natural Gas business, Suncor expects to average 245,000 barrels of oil equivalent per day during the year. At Oil Sands, we'll work to reduce cash operating costs to $10 to $10.50 (US$6.50 to US$6.80) per barrel in 2002.

We'll also seek opportunities to debottleneck our Oil Sands operation to add additional oil production and reduce operating costs.

The company's growth strategy will stay high on our agenda with Suncor continuing construction of the Firebag In-situ Oil Sands Project and progressing plans to expand production from our Oil Sands business up to 550,000 barrels per day over the next decade.

Suncor plans to further invest in wind power, a renewable energy source that holds commercial promise. We will also continue to investigate carbon capture technologies and the purchase of carbon dioxide credits as part of our commitment to manage emissions. During 2002 we expect energy efficiency improvements will reduce greenhouse gas emissions on a per unit of production basis. All of these actions will contribute to our goal of aligning with relevant national and international commitments on climate change.

On the financial side, a key priority for the company is to reduce its $3.1 billion debt. As part of that effort, Suncor has hedged 50% of its 2002 production to mitigate the impact of an uncertain crude oil market on the company's ability to achieve that reduction. We are targeting to reduce Suncor's debt by $200 to $400 million in 2002 and up to an additional $300 million in 2003.

In everything we do, safety will remain our top priority. In 2002, we will pursue improvements in safety and occupational health with a vision of zero injuries to our workforce.

suncor people

More than ever, recognizing the Suncor energy difference means acknowledging the people whose energy drives our difference. It means paying tribute to the 3,000-strong Suncor team who regularly do what it takes to meet our objectives.

I'm fortunate enough to tour our facilities on a regular basis and meet Suncor's employees and there's no part of my job that's more fulfilling. That's why this year's annual general meeting will be held for the first time in the community that is home to our Oil Sands business – Fort McMurray, Alberta. I hope when shareholders are there, they'll take the opportunity to shake the hands of the people who've made commercial oil sands development a success in Canada.

It's appropriate to highlight the achievements of Oil Sands and Project Millennium in particular this year. But it's equally important to recognize the same commitment to everyday excellence that exists across our organization. It's how Sunoco has carved out an Ontario market share that's competitive with those of the national brands and how our Natural Gas business remained competitive while cutting $20 million in annual costs from its operations since 2000.

I'd also like to recognize the Board of Directors for their strategic guidance in the past year and extend special thanks to Bob Wyman, who is leaving Suncor's Board after 15 years of valued service, including six years as Board chairman. Poul Hansen is also retiring after providing six years of distinguished service to Suncor. In addition, Suncor welcomes JR Shaw, executive chair of Shaw Communications, as our new chairman of the Board.

Our executive leadership team is also changing. Barry Stewart retired from the position of executive vice president of In-situ and International Oil in September 2001 after 10 years at Suncor. In June 2002, Mike O'Brien will retire as executive vice president of Corporate Development and chief financial officer. I'd like to thank them both for their distinguished service and the important roles they played in leading Suncor's growth.

Suncor Share Performance
(Cdn$)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	**2001**
Suncor Share Price (TSE)	100	143	154	212	288	507	482	641	821	**1 132**
TSE Integrated Oils Index	100	124	137	164	213	317	253	329	485	**579**
TSE 300 Index	100	133	132	152	194	224	220	290	311	**272**

This chart shows the total cumulative return, assuming the reinvestment of dividends, of $100 invested on December 31, 1992, in Suncor's common shares.

meeting objectives

I invite readers of this report to recognize the energy difference that Suncor delivers. It's built on the essentials of production growth, large resources, profitability, business integration and sustainable development. But most of all, it's built on a record of setting objectives and meeting them.

We have clear objectives ahead that will chart a course to double Oil Sands production again in the next decade. We have the natural resources and human resources we need to reach our goals and a tightly integrated group of businesses. And we have an overarching framework for sustainable development that looks for ways to enhance our communities, reduce our environmental impacts and increase our competitive advantage.

Finally, we have a step-by-step plan for delivering on our objectives and an organization that has been reconfigured to deliver both operational excellence and rapid, disciplined and profitable growth.

The sum of all this is the Suncor energy difference that has enabled us to surpass the $11 billion threshold in market capitalization, reflecting a more than tenfold increase in share price since 1992 and putting Suncor on the radar screen of new institutional investors around the world. As we continue to execute our plans and as the Suncor energy difference becomes increasingly recognized, we will build on our vision of doubling Suncor's shareholder value every five years.

Rick George
President and Chief Executive Officer

Suncor's leadership team

(L to R)

Mike O'Brien
Executive Vice President, Corporate Development and Chief Financial Officer

Tom Ryley
Executive Vice President, Energy Marketing and Refining

Terry Hopwood
Senior Vice President and General Counsel

Kevin Nabholz
Senior Vice President, Major Projects

Rick George
President and Chief Executive Officer

Mike Ashar
Executive Vice President, Oil Sands

Sue Lee
Senior Vice President, Human Resources and Communications

Dave Byler
Executive Vice President, Natural Gas and Renewable Energy

recognize leadership

In 2001, Suncor's organizational structure and leadership assignments were realigned to deliver operational excellence and provide a stronger foundation for future growth.

Renewable energy operations were placed with the Natural Gas business under the direction of Dave Byler, executive vice president. This creates a clean-plus-green energy group with full strategic scope to manage low-emission and no-emission energy development.

In a similar manner, downstream operations were reorganized. Beginning in 2002, Suncor Energy Marketing Inc. and Sunoco will both be managed under the newly named Energy Marketing and Refining business. Tom Ryley, executive vice president, will lead the organization in developing markets for Oil Sands products through the Sarnia refinery and through sales agreements with other refiners and industrial customers. This creates a single marketing management accountability for the entire company.

Suncor also established an internal Major Projects team for directly managing engineering, procurement and construction, led by Kevin Nabholz, senior vice president. This group is responsible for overseeing physical plant expansions for projects over $20 million. This allows each business to focus on delivering increased production at lower costs. It will also contribute to a more reliable transfer between developers and operators of new facilities when growth projects are completed and ready for commissioning.

With these changes in place, the company looks forward to meeting new challenges, leveraging opportunities and achieving solid returns.

the energy difference

GROWTH

Suncor's strategy for profitable growth has nearly quadrupled Oil Sands production since 1992 and is expected to double production again in the coming decade. Suncor is striving to be the largest single supplier of oil sands products and one of the world's top publicly traded crude oil producers.

Suncor's Oil Sands operation is the cornerstone of the company's growth plans. At the end of 2001, Oil Sands reached a production capacity of 225,000 barrels per day.

tighter control from planning to production

Launching the largest capital project in Suncor's history – Project Millennium – didn't just grow production; it grew Suncor's understanding of managing major capital projects. Cost overruns associated with construction, labour requirements and the sheer scale of projects like Millennium should be mitigated in the future by breaking projects into smaller, incremental steps and establishing more direct control of engineering, procurement and construction (EPC).

Direct management of EPC will also contribute to a more reliable transfer between developers and operators when construction is completed.

To realize these benefits, in 2001, Suncor announced the formation of a new Major Projects group to manage future growth projects across the company.

project millennium doubles production

The growth story at Suncor closed an important chapter in 2001 as the company completed Project Millennium – a $3.4 billion, four-year project that increased production capacity to 225,000 barrels per day.

More than just adding capacity for another 40 million barrels per year, Millennium adds a second complete processing operation. This "dual train" approach increases production capacity and provides the flexibility to schedule periodic plant maintenance on one train while continuing to generate production and cash flow from the other.

Millennium had a significant impact on both Suncor and the Canadian economy. At peak construction, more than 6,000 workers were employed, with 650 new full-time positions created on completion. More than 90% of the products and services used to plan and build the expansion came from Canadian-based businesses. And more than $4.2 billion in taxes and royalties are expected to be generated through the life of the project – revenue that will help build infrastructure and services for Canadians for generations to come.

Because responsible development is an integral part of Suncor's growth, the company worked with regional stakeholders throughout Project Millennium's development to address concerns related to increasing oil production.

Taking a $3.4 billion project from planning to operation is no easy task. Dale Denoncourt, a 14-year Suncor Oil Sands employee and now a unit leader with Project Millennium's upgrading operations, was one of many employees who helped in the start-up and commissioning of the expanded facilities.

increased production with reduced impact

Suncor's journey toward a production goal of more than half a million barrels per day is supported by the Firebag In-situ Oil Sands Project, which began construction in late 2001. Firebag is Suncor's first commercial project to use steam assisted gravity drainage (SAGD) technology. SAGD is designed to reach deep bitumen deposits with less impact to the air, water and land than traditional mining methods.

The first stage of Firebag and the associated addition of a vacuum tower to process the bitumen into sour crude, is expected to increase production to 260,000 barrels per day in 2005 at a total cost of about $1 billion. Three additional stages, which have received regulatory approval but are still subject to approval of Suncor's Board of Directors, are expected to increase production at Firebag to a total of 140,000 barrels of bitumen per day by the end of the decade.

voyageur creates long-term growth

In late 2001, Suncor disclosed plans for Voyageur – an expansion project to increase production capacity up to 550,000 barrels per day. Stakeholder consultation for Voyageur is under way and the company is planning to submit detailed plans and initial cost estimates by the end of 2002. Pending regulatory and Board of Directors approval, Suncor plans to initiate construction of Voyageur in 2004.

Voyageur calls for project development to occur in phases, with each step aligned to the company's long-term marketing strategies and the latest environmental standards.

reducing growing pains

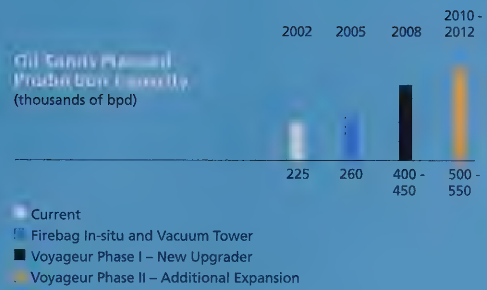
To align Voyageur with Suncor's vision of becoming a sustainable energy company, an environmental impact assessment (EIA) will be completed as part of the company's development application. The EIA will include an assessment of the potential impacts associated with Voyageur, as well as possible cumulative impacts on the region's environment and social infrastructure. Measures to reduce, avoid or mitigate identified impacts will be outlined.

The EIA will also provide details of the Sustainability Legacy program Suncor plans to develop as part of Voyageur. Through stakeholder consultation, Suncor expects this legacy effort to identify innovative ways to eliminate waste, reduce environmental impacts and ensure local communities share in the benefits of Suncor's growth.

As director of Project Approvals, Sue Lowell has helped Suncor gain regulatory approval for Steepbank Mine, Project Millennium, the Millennium vacuum tower and Firebag. Sue now has her sights set on Voyageur. The secret to success is making sure Suncor's plans reflect the needs and expectations of stakeholders.

stepping it up

Suncor's strategy anticipates project development to occur in phases with an ultimate goal of reaching a production capacity of 500,000 to 550,000 barrels per day by 2010 to 2012. The plan assumes an average production rate of 260,000 barrels per day has been achieved in 2005.



market share up, sulphur levels down

Suncor's Sunoco business continues to grow market share in Ontario. In 2001, Sunoco sales were up by 1% over last year, expanding market share for refined petroleum products in Ontario to 18%.

To meet future demand and enhance Sunoco's integration with Oil Sands, the company continues to evaluate refining investment opportunities. Construction of a desulphurization unit to meet the impending interim and final regulated sulphur levels for gasoline, is expected to be completed in 2003.

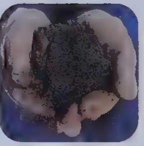
Sunoco has 18% of market share in Ontario.

more natural gas, less CO_2

Suncor's Natural Gas business is generating new production by taking its deep foothills program in a new direction – horizontal. Natural Gas' horizontal drilling expertise in the difficult geology of the Alberta foothills has contributed to 63 million cubic feet per day of new initial gas production in 2001.

An emerging component of Suncor's strategy is increasing production by developing coalbed methane (CBM) – pure natural gas sourced from coal deposits. CBM is present in nearly all coal-bearing areas, but there are a variety of geological factors that determine whether a target formation can be developed economically. Suncor has assembled more than 30,000 net hectares of CBM prospective lands with another 18,000 hectares under option in the United States.

While providing an opportunity to grow natural gas production volumes, Suncor is also evaluating the potential to reduce net emissions of carbon dioxide (CO_2) by pumping waste greenhouse gas into coalbeds where it can be stored indefinitely. An added benefit – injecting CO_2 may increase gas production from the coalbed.



the energy difference

RESOURCES

Suncor's operations and growth plans are focused on developing the Athabasca oil sands deposit, the largest petroleum basin in the world. Suncor's oil sands leases are estimated to contain more than 12 billion barrels of recoverable resources.

Suncor's massive oil sands leases contain enough bitumen to produce 500,000 barrels of oil per day for the next 50 years.

a big backyard

Suncor's leases cover nearly 172,000 hectares, all located relatively close to the company's oil sands processing facilities. Preliminary assessments indicate the Suncor lease north of Firebag is appropriate for both oil sands mining and in-situ development.

Suncor knows where the resources are...

Suncor's leases are estimated to contain more than 12 billion barrels of resources. Unlike conventional oil companies, Suncor does not have the risk and cost of the exploration phase of development so it can make production and upgrading the priority. While the need to replace declining production is driving conventional producers to drill deeper and in more remote locations, Suncor can focus on improving processes and developing technologies to further the company's goal of being one of the lowest cost oil producers in North America.

and how to develop them

While there are no finding costs associated with oil sands exploration, it is necessary to conduct seismic evaluations and core hole drilling to assess the ore deposit.

Core hole drilling, seismic surveys and computer modelling identify the shape, size and quality of the oil-bearing sands. To date, Suncor has shot more than 526 kilometres of seismic surveys and drilled 196 core holes to evaluate the Firebag lease.

As supervisor of employment, Bob Cartwright provides the human resources to deliver Suncor's growth strategy. Cherlyn Brebant drives the heavy haulers that transport the oil sands ore from the mine to extraction. Like many Oil Sands employees, Bob and Cherlyn have more in common than company production targets – they are father and daughter, proudly contributing two generations to Suncor's success.

the energy difference

PROFITABILITY

Suncor recognizes there are many dimensions to operating a successful business, but it all starts with generating shareholder value. Increased production, reduced operating costs and a diverse portfolio of products and services help drive profitability.

Suncor has an ownership interest in nine natural gas plants, providing a strategic link for production in Western Canada.

investing for future profitability in the downstream

Over the last three years, Energy Marketing and Refining has invested more than $14 million in process control equipment to improve operational performance and profitability at its Sarnia refinery. The refinery is expected to benefit from improved yield of higher value products, increased equipment utilization and reduced energy consumption.

Downstream integration provides secure markets for Oil Sands products.

reducing costs

Suncor can't control the price of a barrel of oil so it's important the company focus on controlling operating costs. By increasing production, Suncor expects to realize economies of scale that will reduce cash operating costs per barrel.

In 2002, Oil Sands will work toward a goal of lowering costs to a range of $10 to $10.50 per barrel (US$6.50 to $6.80). To help deliver on this goal, Oil Sands management was realigned to sharpen its focus on operational excellence. A senior vice president of operations responsible for leading mining, extraction and upgrading is now accountable for achieving production and cash operating goals, as well as safety and environmental performance.

Suncor's focus on cost reduction has provided an added benefit – reducing waste and minimizing the company's environmental footprint. For example, upgrades made in 2001 to Oil Sands waste heat recovery units should save over $2 million in fuel costs annually while also reducing greenhouse gas emissions.

capturing the benefit of high commodity prices

Suncor's Natural Gas business is positioned to take advantage of natural gas as the fuel of choice for new power generation and industrial projects. High commodity prices in early 2001 helped Suncor achieve an average natural gas price for the year of $6.09 per thousand cubic feet, driving record revenues for the business.

Dan Crowley, an engineering technologist in Suncor's Grande Prairie office, helps maximize production from over 170 natural gas wells. Suncor's conventional natural gas expertise and assets are focused on three core areas in western Alberta and northeastern British Columbia.

the energy difference

INTEGRATION

Suncor's integration strategy is aimed directly at leveraging maximum value from the company's Oil Sands business. Natural Gas provides an internal 'hedge' by offsetting the cost of energy consumption, while Energy Marketing and Refining helps develop a stable market for increasing oil production.

In the future, Suncor may use satellite technology to track the operations of each of its businesses from a central location. Today, Suncor uses satellites to track mine and pipeline operations and production from conventional wells.

clean and green energy

Suncor's integration isn't just about maximizing the value of what we produce – it's also about focusing on what we don't produce. Low-emission natural gas and no-emission renewable energy form an integral part of Suncor's vision of sustainability by offsetting the company's more emissions-intensive Oil Sands production.

In the retail market, Suncor's Sunoco-branded retail service stations also support sustainable approaches with ethanol-enhanced gasolines. Blending gasoline with ethanol can reduce emissions of carbon monoxide by up to 30% and reduce unburned hydrocarbons. Also, ethanol contains no sulphur, a significant contributor to poor air quality.

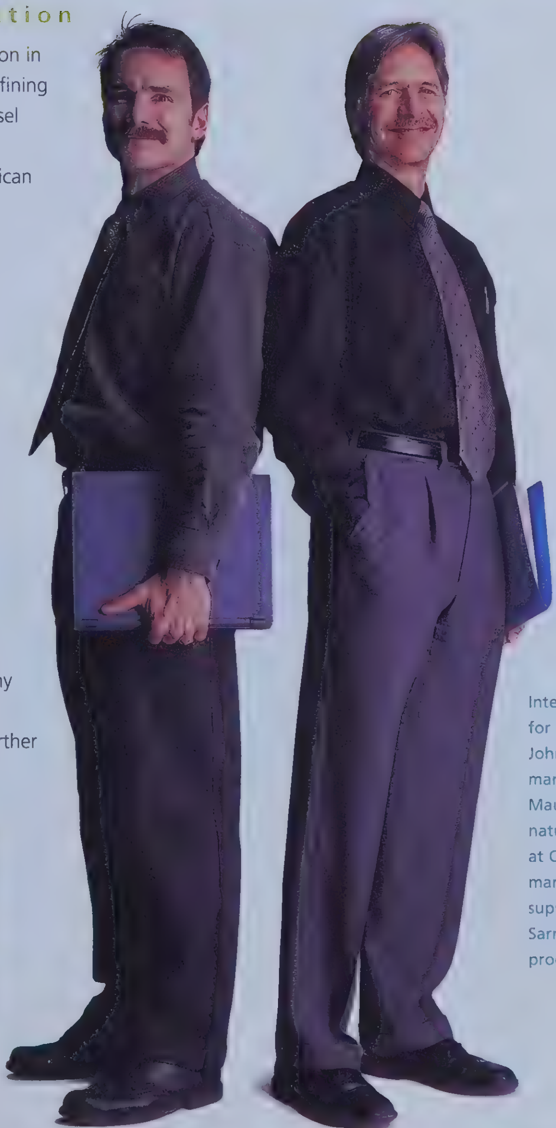
downstream integration

Suncor leverages downstream integration in several ways. Energy Marketing and Refining markets Oil Sands crude oil blends, diesel fuel and by-products to refineries and industrial customers in the North American market. Suncor's marketing strategy includes custom-blending the refinery feedstocks produced to maximize sales while meeting the specific needs of each customer.

Suncor's refinery in Sarnia, Ontario, provides an internal market for portions of Oil Sands crude oil. Gasoline, distillates and petrochemicals are manufactured and then sold to wholesale and retail customers, with the majority distributed through Suncor's controlled channels, including Sunoco-branded service stations.

With Oil Sands production expected to double in the next decade, the company is actively seeking new marketing and refining investment opportunities to further integrate Suncor's businesses.

Suncor's refinery – Sarnia, Ontario



Integration is everyday busine for Maurice Lapierre (R) and John Van Heyst (L). As the manager of natural gas suppl Maurice delivers Suncor's natural gas to fuel operations at Oil Sands. In his role as manager of market technical support, John tops up the Sarnia refinery with feedstock produced at Oil Sands.

the energy difference

SUSTAINABILITY

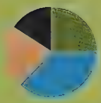
Suncor believes that supplying energy in a manner that meets the environmental, economic and social expectations of stakeholders – customers, shareholders, communities, governments, employees and interest groups – creates a solid foundation for increasing shareholder value over the long term.

Suncor's first renewable energy project, the SunBridge Wind Power Project (a partnership with Enbridge Inc.) is now generating power. SunBridge, located near Gull Lake, Saskatchewan, is part of Suncor's plan to invest $100 million by 2005 in renewable energy.

committed to communities

In 2001, the Suncor Energy Foundation invested more than $3.4 million in 212 registered charities supporting environmental initiatives, community programs and education in science and technology. In 2002, the Foundation expects to contribute $4.6 million to charities across Canada. Suncor also contributes to not-for-profit organizations through sponsorships, Aboriginal affairs and community initiatives.

($ thousands)



Environment	857
Education	1 276
Community Needs	734
Employee & Retiree Donation Program	546

combating climate change

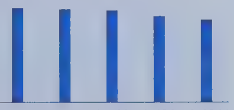
Managing emissions and creating a renewable energy business are only two components of Suncor's plan to address global climate change. In 2001, a major review of greenhouse gas measurement and reporting practices was completed and a technical study to identify additional energy efficiency opportunities was also undertaken.

Suncor is a member of the Carbon Capture Project, a three-year, $45 million joint industry project working to advance the recovery of carbon dioxide from industrial processes for geological disposal. The company is also an investor in an emerging technologies fund managed by Sustainable Asset Management that is identifying leading-edge energy technologies with commercial potential.

working together for cleaner air

Suncor and the Pembina Institute for Appropriate Development co-founded a coalition of corporate, environmental and municipal organizations committed to accelerating development of Canada's renewable energy industry. The group, known as the Clean Air Renewable Energy Coalition, welcomed the federal government's 2001 announcement of incentives for wind power production, an initiative the coalition has promoted since its creation.

Greenhouse Gas Emissions Intensity
(tonnes CO_2 equivalent per m^3 of production)



	1997	1998	1999	2000	2001
Suncor Energy Total Including Offsets	0.482	0.475	0.469	0.439	**0.421***

* Estimate

Ken Hasad shares Suncor's commitment to safety. Ken, a welder in the Oil Sands extraction plant, has worked with Suncor for more than 24 years without a lost-time incident.

management's discussion and analysis

This Management's Discussion and Analysis contains forward-looking statements based on current expectations, but which involve certain risks, uncertainties and assumptions. Actual results may differ materially. See page 44 for additional information.

All financial information is reported in Canadian dollars unless noted otherwise. In 2001, Suncor began to convert natural gas to crude oil equivalent at a ratio of six thousand cubic feet to one barrel. Figures for past years have been restated to reflect this change.

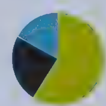
Suncor overview and strategic priorities

Suncor Energy Inc. is an integrated Canadian energy company with its corporate office located in Calgary, Alberta. Suncor's cornerstone business, Oil Sands, mines and upgrades oil sands near Fort McMurray, Alberta, to produce custom-blended refinery feedstocks and diesel fuel. Suncor's conventional Natural Gas production in Western Canada is sold in North American markets, creating an internal hedge against the company's natural gas consumption. The company refines crude oil and markets finished petroleum products through its subsidiary, Sunoco Inc., headquartered in Toronto, Ontario.

Suncor's strategy is based on:

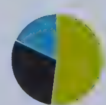
- Expanding Oil Sands facilities to increase oil production and provide greater operational flexibility.
- Developing Suncor's large resource base through oil sands mining and in-situ technology.
- Controlling costs through a strong operational focus, economies of scale and improved management of engineering, procurement and construction on major projects.
- Supporting integration and growth through natural gas production that offsets internal demand and by expanding the downstream marketing of Oil Sands products.
- Actively managing environmental and social issues associated with operations to help build support for Suncor's growth plans among community, government and other stakeholders.

Net Earnings
(per cent)



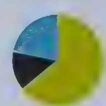
	2001	2000	1999
Oil Sands	**59**	64	71
Natural Gas	**24**	20	17
Sunoco	**17**	16	12

Cash Flow Provided from Operations
(per cent)



	2001	2000	1999
Oil Sands	**52**	62	60
Natural Gas	**30**	22	25
Sunoco	**18**	16	15

Capital Employed
(per cent)



	2001	2000	1999
Oil Sands	**64**	64	55
Natural Gas	**14**	19	29
Sunoco	**22**	17	16

Net Earnings Components

($ millions after income taxes)	**2001**	2000*	1999
Operational earnings**	**433**	414	167
Natural Gas			
Asset divestments	**4**	69	19
Restructuring	**1**	(30)	—
Stuart Oil Shale Project			
Partial asset write-down	**(3)**	(80)	—
Oil Sands			
Start-up expenses – Project Millennium	**(90)**	(9)	—
Impact of provincial income tax rate reductions on opening future income tax balances***	**43**	13	—
Net earnings	**388**	377	186

Cash Flow from Operations Components

($ millions)	**2001**	2000	1999
Operational cash flow**	**1 061**	1,009	591
Natural Gas			
Restructuring costs	**(1)**	(9)	—
Oil Sands			
Start-up expenses & overburden removal – Project Millennium	**(229)**	(42)	—
Cash flow provided from operations	**831**	958	591

Income Tax Rate Changes

Impact of provincial income tax rate reductions on opening future income tax balances*

($ millions)	Oil Sands	Natural Gas	Sunoco	Corporate	**Total 2001**	2000
	31	9	10	(7)	**43**	13

* The determination of operational earnings for 2000 has been restated to be consistent with the treatment and presentation in 2001 of the impact of income tax rate reductions.

** Suncor's presentation of operational earnings and operational cash flow are provided to enhance readers' understanding of the factors impacting Suncor's operational and financial performance and should not be used to compare Suncor's financial results with those of other companies. For comparability purposes readers should rely on the reported net earnings and cash flow provided from operations and the related per share information, which are prepared and presented in accordance with Canadian generally accepted accounting principles in the Consolidated Financial Statements.

*** See Note 5 to the Consolidated Financial Statements.

For information related to quarterly sales, net income and net income per share for the years 2001 and 2000 refer to the information under the heading Quarterly Summary on pages 69 and 70 of this 2001 Annual Report, which information is incorporated by reference into this Management's Discussion and Analysis.

earnings analysis

Net Earnings Up 3% in 2001

Net earnings for the year increased to $388 million, up from $377 million in 2000. Cash flow provided from operations was $831 million, compared with $958 million in 2000.

During 2001 and 2000, several transactions impacted net earnings and cash flow provided from operations that were not viewed as ongoing. These transactions in 2001 included start-up expenses of Suncor's major oil sands expansion, Project Millennium, restructuring cost adjustments and a divestment gain in Natural Gas, adjustments related to the revaluation of opening future provincial income tax balances due to a reduction in income tax rates and Suncor's sale of the Stuart Oil Shale Project. Non-operational transactions are explained in the Notes to the Consolidated Financial Statements.

Operational earnings in 2001 increased to $433 million from $414 million in 2000. The $19 million increase was primarily the result of increased Oil Sands sales, lower crude oil hedging losses, higher natural gas prices, the benefit of a royalty rate reduction for Oil Sands production and higher downstream retail gasoline margins and volumes. These factors were partially offset by lower crude oil prices, the widening of light/heavy crude oil differentials, the impact of two maintenance shutdowns that halted Oil Sands production for a total of 16 days and higher operating expenses and interest charges.

Operational cash flow in 2001 increased over 2000 primarily due to the same factors that increased earnings. Operational cash flow also increased as a result of the favourable income tax impact from the sale of the company's interest in the Stuart Oil Shale Project.

These favourable factors were partially reduced by recognition at December 31, 2001 of the $32 million estimated payment to be made in 2002 under Suncor's long-term employee compensation programs. Subsequent to year-end it was determined that 2001 performance targets were achieved and the final payout will be based upon the average weekly closing common share price in the first quarter of 2002. Based on current share prices it is estimated the total cash cost of these programs will be approximately $108 million. The payment with respect to these programs in the second quarter of 2002 will be $72 million. This payment is approximately $30 million higher as a result of elections subsequent to the year-end with respect to the form of payment under one component of these programs. This $30 million change will decrease cash flow provided from operations in the first quarter of 2002. Up to the end of 2001 the after-tax cumulative cost since the programs' inception in 1997 that had been charged against Suncor's earnings was $67 million.

Consolidated Earnings Analysis

Sales and other operating revenues were $3,990 million in 2001, up from $3,385 million in 2000. The increase was primarily the result of the items discussed below:

- During the first quarter of 2001, Suncor changed the methodology of accounting for sales from its upstream to downstream operations, as explained in Note 18 to the Consolidated Financial Statements. This change increased revenue.
- Higher natural gas prices were more than offset by a decrease in crude oil prices due to weakening demand. Also impacting crude oil operating revenues were lower revenues from sour crude oil sales due to widening of the light/heavy crude oil differential and a higher proportion of lower value sour crude oil sales in 2001 (35% of total sales volumes versus 31% in 2000). The increase in sour crude oil production was primarily due to initial production from Project Millennium that could not be upgraded from sour to sweet crude oil until the hydrotreating units were commissioned late in 2001. Revenues were favourably impacted by a one-time $18 million pricing adjustment related to a large supply contract calculated retroactively to 1999.
- Sales volumes for the year were unfavourably impacted by two maintenance shutdowns (one planned and one unplanned) at the Oil Sands operations that totalled 16 days.
- Increased revenues of $99 million were associated with a crude oil business that commenced in 2001 to generate additional income by buying and selling production of other companies. The purchase of the crude oil for resale is shown in purchases of crude oil and products in the Consolidated Financial Statements. This activity did not have a significant impact on earnings or cash flow in 2001.

The purchases of crude oil and products increased year-over-year by $584 million. This increase includes the impact, as noted above, of the change in accounting methodology for sales of $473 million between upstream and downstream operations. Costs for crude oil and other product purchases also increased due to a number of factors:

- As noted above, Suncor initiated a business which purchased third party crude oil for resale.
- Two maintenance shutdowns at the Sarnia refinery resulted in higher product purchases being incurred to meet customer commitments.
- Two maintenance shutdowns at Oil Sands, which halted production for a total of 16 days, also resulted in more third party purchases of crude oil by the Sarnia refinery.
- Higher natural gas costs and volume increases were associated with the retail marketing of natural gas in Ontario.

These cost increases were partially offset by a reduction in the cost of crude oil and refinery feedstocks purchased from third parties due to a 14% decline in the benchmark WTI crude oil price in 2001 from 2000.

Operating, selling and general expenses increased to $1,010 million in 2001, up from $918 million in 2000. The increase was primarily due to:

- Higher refining costs reflecting increased energy costs and higher maintenance costs associated with two maintenance shutdowns at the Sarnia refinery.
- Lower foreign exchange gains in 2001 with respect to the Stuart Oil Shale Project.

- Higher compensation, including a $10 million cost associated with the long-term compensation program (as described in Note 12(b) to the Consolidated Financial Statements).
- Higher mining costs due to increased production and ore variability.
- Higher research and development costs with respect to new technology assessments.

The above factors were partially offset by lower production costs in Suncor's Natural Gas business due to the 18% production decline in 2001 compared to 2000, and lower costs associated with the Stuart Oil Shale Project in 2001, compared to 2000 due to divestment of this project in April 2001.

In 2002 insurance costs are expected to increase by an estimated $14 million (175%). The increase primarily reflects higher premiums on property and business interruption insurance due to the tightening of insurance market capacity. As noted in Note 14(b) to the Consolidated Financial Statements, the deductible limit for the business interruption policy will be increased to $415 million (US$260 million) for 2002 from $70 million (US$45 million) in 2001.

Exploration expenses decreased by $31 million in 2001, primarily as a result of lower dry hole costs. Royalty expenses decreased by $65 million in 2001 to $134 million. The decrease was primarily due to a lower Crown royalty rate for Oil Sands production, which was reduced to 1% of gross revenue compared to 5% in 2000 and lower Natural Gas sales levels. These favourable factors were partially offset by higher royalties due to higher natural gas prices and increased production from Oil Sands.

Depreciation, depletion and amortization (DD&A) decreased by $5 million to $360 million in 2001 from $365 million in 2000. The decrease was primarily due to an $8 million decrease in DD&A in the Natural Gas business as a result of the 2000 asset divestment program. Most of the Project Millennium assets at Oil Sands will be depreciated over 40 years. Over the life of the assets, depreciation will average $90 million per year, with higher depreciation in the initial years and lower depreciation in the later years. In 2002 depreciation will be approximately $115 million. Overburden amortization is expected to increase in 2002 to approximately $160 million (pre-tax).

Interest costs (before capitalization of interest on projects) increased in 2001 to $143 million, from $112 million in 2000, primarily reflecting higher debt levels, partially offset by lower variable interest rate costs. Long-term borrowings at the end of 2001 were $3.1 billion, up from $2.2 billion at the end of 2000, reflecting expenditures of approximately $1 billion on Project Millennium in 2001. With Project Millennium commencing commercial operations in

Consolidated Financial Results

($ millions)	**2001**	2000	1999
Net earnings	**388**	377	186
Cash flow provided from operations	**831**	958	591
Investing activities	**1 680**	1 607	1 290
Dividends – common shares	**75**	75	75
– preferred securities	**48**	47	37
Long-term borrowings	**3 113**	2 192	1 306

Industry Indicators

(average for the year unless otherwise noted)	**2001**	2000	1999
West Texas Intermediate (WTI) crude oil US$/barrel at Cushing	**25.90**	30.25	19.30
Canadian 0.3% par crude Cdn$/barrel at Edmonton	**39.34**	44.56	27.50
Light/heavy crude oil differential US$/barrel – WTI @ Cushing/Bow River @ Hardisty	**9.51**	6.84	3.42
Natural gas US$/thousand cubic feet at Henry Hub	**4.38**	3.90	2.27
Natural gas (Alberta spot) Cdn$/thousand cubic feet at Empress	**6.31**	5.08	3.00
Canadian natural gas exports to the U.S., trillions of cubic feet	**3.8***	3.60	3.40
New York Harbour 3-2-1 crack US$/barrel**	**4.42**	5.45	2.47
Refined product demand (Ontario) percentage change over prior year	**(1.6)***	2.6	3.8
Exchange rate: Cdn$:US$	**0.64**	0.67	0.67

* Estimate

** New York Harbour 3-2-1 crack is an industry indicator measuring the margin on a barrel of oil for gasoline and distillate. It is calculated by taking 2 times the New York Harbour gasoline margin plus 1 times the New York Harbour distillate margin and dividing by 3.

2002, interest charges that were capitalized in 2001 will now be expensed in 2002, thereby reducing 2002 earnings. Interest capitalized on Project Millennium in 2001 was approximately $120 million.

Net interest costs increased from $8 million in 2000 to $18 million in 2001 primarily due to the costs associated with the Stuart Oil Shale Project.

Subsequent to year-end, Suncor issued US$500 million of 7.15% unsecured notes due 2032 from a US$1 billion unallocated shelf prospectus. The net proceeds from the sale were used to repay commercial paper and bank borrowings. Following this transaction, Suncor had approximately $2,050 million of fixed rate borrowing at an average cost of 6.7%. The balance of Suncor borrowings are at floating interest rates. Short-term floating interest rates are at historical lows and total interest expense will be influenced by changes in short-term rates.

Financing costs in 2002 could also be higher or lower due to foreign exchange gains or losses as the January 2002 debt issued will be restated ("marked-to-market") at the prevailing exchange rate between the Canadian and U.S. dollar. This could create volatility in earnings. It is anticipated that a $0.01 change in the exchange rate would have an estimated $5 million pre-tax impact on earnings with respect to the U.S. dollar denominated debt.

Interest expense will be influenced by the company's anticipated change in its debt portfolio. For the past few years a high percentage of Suncor's debt was at floating interest rates. With the completion of Project Millennium, Suncor intends to replace bank debt with longer-term fixed rate public market debt. During 2001 Suncor issued $500 million medium-term notes as well as the above noted U.S. debt issue in early 2002. Subsequent to year-end, Suncor has also filed a shelf prospectus with Canadian securities regulatory authorities, enabling it to issue up to a further $500 million in medium-term notes in Canada if required. Suncor plans to manage the fixed versus floating rate exposure with the use of interest rate swaps.

Taxes, other than income taxes, increased by $6 million to $367 million primarily due to higher sales volumes of taxable products (mainly transportation fuels) in Sunoco.

Suncor's effective income tax rate in 2001 was 24%. This includes favourable adjustments of $43 million (9%) for provincial tax rate reductions and $9 million (1%) for federal tax rate reductions related to revaluation of opening future income tax balances. In 2000 the effective income tax rate was 39%, including $13 million (2%) in favourable provincial tax rate adjustments related to revaluation of opening future income tax balances. Also, in 2001 there was the recognition of lower provincial taxes of $6 million due to provincial deductibility of Crown royalties in excess of the federal resource allowance deduction. This deduction reduced the 2001 effective rate by 1%. In 2000 there was a similar provincial reduction of $13 million, which reduced the effective tax rate by 2%.

Suncor believes its effective tax rate in 2002 will be approximately 38%. Based upon the prior year's capital investment levels and planned future investment levels, Suncor does not expect its upstream operations to be cash taxable until the latter half of the current decade. This assessment can change depending upon such factors as profitability and capital investments.

Dividends

During 2001, Suncor's quarterly common share dividend was $0.085 per share, unchanged from 2000. Dividend levels are reviewed quarterly in light of Suncor's growth-related initiatives, financial position, financing requirements, cash flow and other factors considered relevant by the Board of Directors.

Corporate Office Expenses

Corporate office after-tax expenses decreased to $92 million in 2001 from $117 million in 2000. Operational expenses in 2001 exclude the $3 million write-down of the investment in the Stuart Oil Shale Project and a $7 million unfavourable provincial income tax rate adjustment. Operational expenses in 2000 exclude an $80 million write-down of the Stuart Oil Shale Project.

Excluding these factors, the increase in operational expenses in 2001 to $82 million from $37 million in 2000 was primarily due to lower foreign exchange gains, higher research and development costs with respect to new technology assessments, higher compensation costs including the costs associated with the company's long-term compensation program and higher interest costs.

The corporate centre had a net cash deficiency of $165 million in 2001 compared to a net cash deficiency of $76 million in 2000. The increase was primarily due to settlement in 2001 of outstanding 2000 obligations and income tax refunds expected to be received in 2002.

outlook

Suncor recognizes that operational excellence is important to achieving improved financial returns. Safe and efficient operations reduce the risk of production loss, environmental liability and the higher costs incurred in conducting unscheduled maintenance. In 2002, all of Suncor's businesses plan to continue to focus on base business excellence to improve operational reliability. Plans to apply technological advancements that are intended to increase the efficiency of each business, reduce costs and improve environmental and safety performance will be a key focus.

Production Growth at Oil Sands

Suncor plans to leverage its existing facilities and operational experience with the intention of increasing Oil Sands production in phases over the next decade. (See Oil Sands Overview page 30.)

Project Management

Engineering, procurement and construction (EPC) of Suncor's planned major expansions will be managed directly by the company's newly created Major Projects group. Management believes direct control of EPC can assist Suncor to reduce costs and improve the efficiency of the transition between construction and operation.

Integration

Natural gas production and downstream marketing strategies will continue to be an important part of Suncor's corporate strategy. (See Natural Gas Overview page 36 and Sunoco Overview page 40.)

Sustainability

As the company expands its hydrocarbon-based businesses, management believes Suncor must also work toward the development of renewable energy. Renewable energy has the potential to reduce environmental impacts and create additional business investment opportunities.

As part of the company's plans to invest $100 million in renewable energy projects by 2005, the SunBridge Wind Power Project was constructed in 2001. SunBridge is a $20 million partnership (50:50) between Suncor and Enbridge Inc.

Suncor's effort to reduce greenhouse gas emissions is reflected in its pursuit of greater internal energy efficiency – with the dual objective of cost savings and improved environmental performance. Suncor also plans to invest in emissions offsets and carbon capture research and development. The company's goal is to align operations with relevant national and international commitments to limit greenhouse gas emissions.

Workplace health and safety will remain a priority at all Suncor businesses and work sites.

risk/success factors affecting performance

The issues Suncor must manage include, but are not limited to commodity prices, environmental regulations and regional labour issues including those specific issues discussed under Risk/Success Factors Affecting Performance for each Suncor business.

Suncor believes that while the planned increases in Oil Sands production will provide strategic advantages, they also present issues that will require prudent risk management.

Commodity Prices

Suncor's future financial performance remains closely linked to hydrocarbon commodity prices, which can be influenced by global and regional supply and demand, worldwide political events and the weather. These factors, among others, can result in a high degree of price volatility. In the last three years for example, the industry has seen the monthly average price for benchmark WTI crude oil range from a low of US$12 per barrel to a high in 2000 of US$34.25 per barrel. During the same period, the natural gas Henry Hub benchmark monthly average price ranged from a low of US$1.69 per thousand cubic feet (mcf) to a high of US$9.79 per mcf.

Crude oil and natural gas prices are based on a U.S. dollar benchmark that results in Suncor's earned prices being influenced by the Canadian/U.S. currency exchange rate, thereby creating another element of uncertainty for the company. The continued weakness in the Canadian dollar versus the U.S. dollar in 2001 increased Suncor's revenues and earnings, as measured in Canadian dollars. In the future, Suncor's revenues will continue to be influenced by the value of the Canadian dollar relative to foreign currencies.

Hedging

Suncor cannot control or accurately predict the prices of crude oil or natural gas, or currency exchange rates. For this reason, the company has a hedging program that fixes the prices of crude oil and natural gas for a percentage of Suncor's total production. Suncor has entered into a foreign exchange contract for 2002, but currently has no plans to enter into foreign exchange contracts beyond 2002. Suncor's risk management objective with its hedging program is to lock in prices on a portion of the company's future production to reduce its exposure to market volatility and support the company's ability to finance growth. Refer to Note 17(b) to the Consolidated Financial Statements for details of revenue hedges.

The Audit Committee and the Board of Directors meet with management regularly to assess Suncor's hedging thresholds in light of its price forecast and cash requirements. To add more certainty to Suncor's ability to finance future capital programs and repay debt, the Board authorized hedging up to 30% of the company's crude oil volumes between 2003 and 2006. In 2001, hedging decreased Suncor's earnings by $148 million. In 2000, hedging decreased earnings by $259 million.

Environmental Regulation Risk/Success Factors

Environmental legislation affects nearly all aspects of Suncor's operations. Environmental legislation imposes certain standards and controls on activities relating to mining, oil and gas exploration, development and production and the refining, distribution and marketing of petroleum products and petrochemicals and requires companies engaged in those activities to obtain necessary permits to operate. Also, environmental assessments and approvals are required before initiating most new projects or undertaking significant changes to existing operations.

In addition to these specific known requirements, Suncor expects changes to environmental legislation will likely impose further requirements on companies operating in the energy industry. Some of the issues include the possible cumulative impacts of oil sands development in the Athabasca region; the need to reduce or stabilize various emissions; issues relating to global climate change, including the potential impacts of government regulation; land reclamation and restoration; water quality; and reformulated gasoline to support lower vehicle emissions. Changes in regulation could have an adverse effect on Suncor in terms of product demand, product formulation and quality, methods of production and distribution and operating costs. The complexity of these issues makes it difficult to predict their future impact on the company. Management anticipates capital expenditures and operating expenses could increase in the future as a result of the implementation of new and increasingly stringent environmental regulations.

Crude Oil Hedging Program
(at December 31, 2001)

	2002	2003	2004	2005	2006
■ Thousands of barrels per day (kbpd) of Annual Crude Oil Hedged	84	44	11	15	—
● Current Annual Limits (kbpd)	105	66	68	68	68
Percentage of Annual Crude Oil Hedged	40	20	5	7	0
Hedged Price – Cdn$ per barrel	31.99	33.44	33.44	34.37	—

Other Factors

Other critical factors affecting Suncor's financial results include volumes and margins of refined product sales, success of the natural gas exploration and development program, interest rates and the company's ability to manage both day-to-day operating costs as well as project costs. For further discussions of possible risk factors and uncertainties which may affect the company, refer to page 44 at the end of the MD&A and to the company's Annual Information Form, on file with securities regulators or available from the company.

Sensitivity Analysis

The following sensitivity analysis shows the main factors affecting Suncor's annual pre-tax cash flow from operations and after-tax earnings based on actual 2001 operations. The table illustrates the potential financial impact of these factors applied to Suncor's 2001 results. With Project Millennium commissioning complete, Oil Sands production is expected to increase over 2001 levels and thus the sensitivity analysis on a 1,000 barrel per day change in production may not be indicative of future results. A change in any one factor could compound or offset other factors.

liquidity and capital resources

Suncor's growth has been funded by a combination of internally generated funds and increased debt. Net debt increased to $3.1 billion at the end of 2001, approximately $900 million higher than at the end of 2000.

Sensitivity Analysis

	2001 Average	Change	Approximate change in Pre-tax cash flow from operations ($ millions)	After-tax earnings ($ millions)
Oil Sands				
Price of crude oil ($/barrel)	**29.17**	US$1.00	35	25
Sweet/sour differential ($/barrel)	**8.29**	US$1.00	19	13
Sales (barrels/day)	**121 500**	1 000	10	7
Natural gas				
Price of natural gas ($/thousand cubic feet)	**6.09**	0.10	5	3
Production of natural gas (millions of cubic feet/day)	**177**	10	15	6
Sunoco				
Retail gasoline margin (cents/litre)	**6.6**	0.1	2	1
Refining/wholesale margin (cents/litre)	**5.7**	0.1	3	2
Consolidated				
Exchange rate: Cdn$:US$	**0.64**	0.01	14	10
Interest rate	**2.7%***	1%	2	1

* Borrowings with interest at variable rates averaging 2.7% at December 31.

Planning Assumptions

	2001 Actual Average for the year	Current Plan Average next 3-year range	Last Year's Plan Average next 3-year range
Crude oil – WTI US$ per barrel	**25.90**	19.00 – 21.00	18.00 – 19.00
Natural gas – US$/thousand cubic feet @ Henry Hub	**4.38**	3.00 – 3.45	3.00 – 3.50
Exchange rate: Cdn$:US$	**0.64**	0.65 – 0.69	0.69 – 0.71

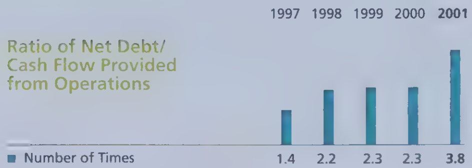
The above are planning assumptions and are not estimates or predictions of actual future events or circumstances. Because this table does not incorporate potential cross-relationships, it would not necessarily accurately predict future results.

With the completion of Project Millennium, capital and exploration investment activity is planned to decrease to $900 million in 2002, down from $1.7 billion in 2001 and $2 billion in 2000.

Suncor plans to make debt reduction one of its priorities as it prepares for the next stages of growth. Management believes a phased approach to future growth projects should improve the ability to manage project costs, providing further opportunities for debt reduction. This approach, along with anticipated higher Oil Sands sales levels and the hedging of approximately 50% of crude oil production in 2002, should allow for the reduction in both the absolute debt level and the net debt/cash flow provided from operations ratio. Suncor's target for this ratio is in the range of 1.5 to 2.0 times at mid-cycle pricing. At the end of 2001 this ratio was 3.8 times, higher than the expected 2001 short-term peak of 3.5 times Suncor targeted last year. The increase was due to the higher than estimated Project Millennium spending.

Other key factors that can contribute to a reduction in this ratio are operational performance and crude oil prices, and to a lesser degree natural gas prices and downstream margins. Management does not expect crude oil prices will be sustained at the average level achieved in 2001. Suncor's business plans are based upon assumptions, including a crude oil price assumption lower than the 2001 WTI average price per barrel of $25.90. Based on current planning and operational assumptions, Suncor believes net debt could be reduced by $200 to $400 million in 2002, reducing the net debt to cash flow provided from operations ratio to the two times range in 2002.

Ratio of Net Debt/ Cash Flow Provided from Operations



Ratio could decline over the next two years depending upon such factors as commodity price assumptions and the integration of Project Millennium.

Oil Sands overview

Suncor's Oil Sands business, located near Fort McMurray, Alberta, is the cornerstone of the company's growth plans. The business mines oil sands, extracts the bitumen and upgrades it into a variety of refinery feedstocks and diesel fuel.

Relative to conventional oil exploration and production, oil sands reserves and recovery rates are generally better defined and more predictable, providing Suncor with what management believes is a more stable foundation for production growth.

Oil Sands strategy for profitable growth is based on:

- Applying proven as well as new technologies to increase oil production.
- Reducing costs through application of technologies, economies of scale, direct management of growth projects and more efficient operations.
- Building strategic business relationships to mitigate risk and capture value from the production of energy, steam and by-products.
- Implementing growth in a manner that supports Suncor's vision of becoming a sustainable energy company.

Oil Sands progressed this strategy in 2001 by commissioning Project Millennium, a $3.4 billion expansion that nearly doubled Oil Sands production capacity to 225,000 barrels per day (bpd) and improved operational flexibility by adding a second upgrader. This expansion is expected to reduce operating costs through process improvements and economies of scale.

In 2001 Suncor received regulatory approval for the Firebag **In-situ** Oil Sands Project, a commercial scale in-situ project planned to supply an additional 140,000 barrels of bitumen per day by the end of the decade.

Also in 2001, Suncor announced plans for Project Voyageur, which call for a staged expansion of Suncor's oil sands and in-situ facilities. Suncor has initiated the consultation process for the project and plans to apply for regulatory approval in late 2002.

Voyageur requires approval of regulators and Suncor's Board of Directors, as well as development of engineering, construction and production plans for each phase and favourable fiscal and market conditions. Any expansion decisions will be aligned with the company's long-term marketing strategies.

To support increased production, Suncor is working with other companies at the Oil Sands plant site. In 2001, TransAlta Energy Corporation commenced operation of its **cogeneration** facility at the plant. A portion of the energy from the facility will help meet current energy needs of the Oil Sands operation while mitigating fluctuating energy costs and lowering carbon dioxide emissions per unit of production.

results of operations and investing activities

2001 vs. 2000

Oil Sands – Summary of Results

($ millions unless otherwise noted)	**2001**	2000	1999
Revenue	**1 385**	1 336	889
Production (thousands of bpd)	**123.2**	113.9	105.6
Average sales price ($/barrel)	**29.17**	31.67	23.84
Operational earnings	**342**	324	167
Net earnings	**283**	315	167
Cash flow provided from operations	**486**	655	405
Total assets	**6 409**	5 079	3 178
Investing activities	**1 476**	1 715	1 085
ROCE (%)	**20.1**	22.8	12.9
ROCE (%)*	**6.4**	10.6	9.2

* ROCE – Return on average capital employed. Includes capitalized costs related to major projects in progress.

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in-situ
In-situ refers to methods of extracting heavy oil from deep deposits of oil sands through horizontal drilling with minimal disturbance of the ground cover.

cogeneration
The simultaneous production of electricity and steam from one energy source.

Revised Cost Estimates for Growth Projects

The capital cost of Suncor's Project Millennium was approximately \$3.4 billion, a \$1.4 billion increase over the original 1997 estimate of \$2 billion. The capital cost increased primarily as a result of higher labour, fabrication and material costs and changes in project scope. The additional capital costs were financed through internally generated cash flow and additional borrowing.

When combined with an associated expansion of Suncor's upgrader, the first phase of the Firebag In-situ Oil Sands Project is expected to cost about \$1 billion. This estimate is \$250 million higher than Suncor estimated in 1999 when planning on the project was first initiated. The revised estimate reflects construction of additional common infrastructure to support subsequent stages of Firebag, future capacity improvements of the company's upgrader and other costs reflecting Suncor's experience with construction on Project Millennium.

net earnings analysis

Oil Sands Earnings Decrease 10%

Oil Sands net earnings were \$283 million in 2001, compared with \$315 million in 2000. Operational earnings of \$342 million in 2001 exclude a \$31 million favourable income tax rate reduction and \$90 million in Project Millennium start-up expenses. Operational earnings in 2000 were \$324 million. The increase in operational earnings of \$18 million in 2001 was primarily due to higher volumes and lower Crown royalty payments, offset by higher costs and an 8% decrease in crude oil prices from 2000. If the incremental start-up volumes had been excluded from the determination of 2001 operational earnings, it is estimated that operational earnings in 2001 would have been lower than in 2000.

During 2001, Suncor initiated a new business to generate additional income by buying and selling the crude oil production of other companies. The purchase of crude oil for resale, \$96 million in 2001, is shown in the purchases of crude oil and products line in the Consolidated Financial Statements. These activities did not have a significant impact on earnings or cash flow.

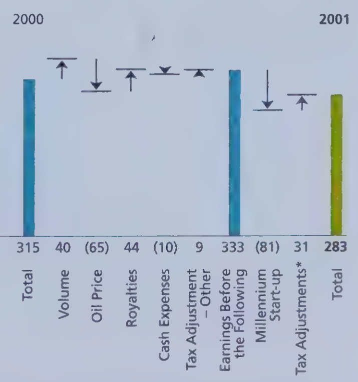
Oil Sands Crude Oil Prices Decrease 8%

Oil Sands crude oil prices in 2001 averaged \$29.17 per barrel, compared with \$31.67 per barrel in 2000. WTI benchmark prices decreased 14% to an average of US\$25.90 per barrel in 2001 from an average of US\$30.20 per barrel in 2000. Price was further negatively impacted by wider sweet and sour differentials combined with a proportionately higher volume of lower value sour crude sales. The effect of a lower crude price was partially offset by decreased hedging losses of \$224 million in 2001, compared with \$407 million in 2000. The combined impact of the above pricing factors reduced earnings in 2001 by \$65 million after-tax from 2000 levels.

Oil Sands Production Increases 8%

Oil Sands increased production in 2001 for the ninth consecutive year to an average of 123,200 bpd, up from 113,900 bpd in 2000, mostly due to the start-up of Project Millennium in the fourth quarter. With the Millennium upgrading facilities in operation, production averaged a record-breaking 180,000 bpd in December 2001.

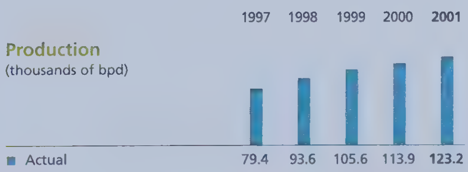
Bridge Analysis of Net Earnings
(Cdn\$ millions)



Lower crude price and increased costs associated with start-up of Project Millennium, partially offset by record sales volume and decreased royalties and income taxes, resulted in a 10% decrease in earnings.

* Provincial income tax rate adjustment on opening future tax balances.

Production
(thousands of bpd)



Oil Sands achieved record production of 123,200 bpd in 2001. As the new Millennium facilities are fully integrated with base operations, Oil Sands expects production to average 210,000 bpd in 2002.

Production in 2001 was impacted by a planned **maintenance shutdown** of the fractionating tower in the second quarter that halted production for a total of nine days and an unscheduled seven-day maintenance shutdown of the same facility in the fourth quarter.

Higher sales levels in 2001 resulted in a year-over-year earnings improvement of $40 million.

Because production commenced from Millennium upgrading facilities before the hydrotreating units were fully commissioned, sour crude inventories increased in late 2001. The sour crude inventory is expected to be reduced in the first half of 2002. Since the majority of the anticipated future incremental production from Project Millennium is expected to be upgraded sweet crude, an improved crude sales mix is expected in 2002. Oil Sands is targeting production of approximately 55% light sweet crude, 12% diesel and 33% light sour crude in 2002 compared to the 2001 mix of 46% light sweet crude, 12% diesel and 42% light sour crude.

Royalties

Crown royalties in effect for Suncor's existing Oil Sands operations require payments to the Government of Alberta of 25% of net revenues less allowable costs (including capital expenditures), subject to a minimum payment of 1% of gross revenues, a rate that Suncor expects to pay until 2009. This expectation is based on assumptions relating to future oil prices, production levels, operating costs and capital expenditures. In 2001 Oil Sands made royalty payments of 1% of gross revenues, compared to 5% in 2000.

Crown royalties payable by Suncor to the Government of Alberta decreased to $15 million in 2001 from $87 million in 2000 as a result of the 1% royalty rate and lower commodity prices that were only partially offset by higher sales levels. The lower Crown royalties were partially offset by a $4 million increase in royalties paid to Anadarko Petroleum Corporation (Anadarko) due to more tonnes mined in 2001 from the lease on which Anadarko has a royalty interest. Mining on the lease is expected to be completed in 2002.

The decrease in total royalties expensed increased earnings by $44 million after-tax.

Expenses Increased

Cash expenses of $493 million in 2001 increased by 3% over 2000 levels, reducing Oil Sands earnings by approximately $10 million after-tax. The increase in expenses was a result of higher energy costs driven by higher natural gas prices, higher sales volumes and higher mining costs, including the costs associated with minimizing the impact of ore variability.

Non-cash charges (depreciation, depletion and amortization) remained flat year-over-year due to offsetting factors.

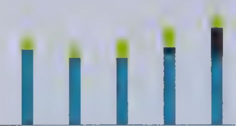
Per Barrel Operating Costs

Cash operating costs, excluding $5.10 per barrel Project Millennium start-up and **overburden** removal expenditures, decreased to $11.90 per barrel in 2001. This compares to $12.55 in 2000 (excluding $1.00 per barrel in Project Millennium start-up and overburden removal costs in 2000). The decrease of $0.65 per barrel is due to higher volumes, partially offset by higher energy costs.

Not all the expenses associated with the additional volumes from Project Millennium are included in the $11.90 per barrel cash operating cost. As a result, the $11.90 per barrel cash operating cost is not indicative of cash operating costs in the future.

Total cash and non-cash operating costs per barrel in 2001 were $14.50 ($19.60 including Project Millennium start-up and overburden removal expenses), compared with $16.25 per barrel ($17.25 per barrel including Project Millennium

Cash and Total Operating Costs
(Cdn$ per barrel)



	1997	1998	1999	2000	**2001**
Cash Operating Cost	13.25	11.75	11.70	12.55	**11.90**
Start-up Expenditures Project Millennium	—	—	—	1.00	**5.10**
Total Cash Cost	13.25	11.75	11.70	13.55	**17.00**
Non-cash Cost	2.55	2.25	3.35	3.70	**2.60**
Total	15.80	14.00	15.05	17.25	**19.60**

Total cash costs increased due to higher energy costs and Project Millennium start-up expenditures. Non-cash expenses decreased due to reduced maintenance shutdown amortization costs resulting from deferral of a maintenance shutdown to 2002.

maintenance shutdown
Preventative maintenance activities that involve shutting down major parts of a facility or an entire facility.

overburden
Surface material that must be removed before mining. Consists of muskeg, glacial deposits and sand.

expenses) in 2000. The $1.75 per barrel decrease in total operating costs (excluding Project Millennium expenses) was due to the same factors affecting cash operating costs.

Oil Sands cash operating margin was $11.50 per barrel in 2001, compared with $15.80 per barrel in 2000. The following factors influenced cash margins during the year:

- Lower crude prices (before hedging) had an unfavourable impact of $7.10 per barrel.
- Lower hedging losses had a favourable net impact of $4.60 per barrel.
- Cash operating costs had a favourable impact of $0.65 per barrel.
- Project Millennium start-up and overburden removal expenditures had an unfavourable impact of $4.10 per barrel.
- Lower royalties had a favourable impact of approximately $1.65 per barrel.

net cash deficiency analysis

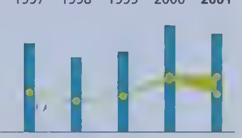
Cash flow provided from operations was $486 million in 2001, compared with $655 million in 2000. The decrease of $169 million was primarily due to lower earnings resulting from Project Millennium's $141 million start-up expenses in 2001, $126 million higher than 2000 spending. Higher overburden removal expenditures (mostly related to Project Millennium) of $119 million, compared to 2000 expenditures of $75 million, a $10 million increase in reclamation spending to $22 million, and recognition of the estimated employee long-term compensation program payment in the amount of $16 million were other factors that reduced cash flow provided from operations compared to 2000 by $43 million.

Oil Sands working capital increase in 2001 was $35 million, compared to $169 million increase in 2000. This reduction is primarily due to lower trade receivables in 2001, reflecting lower crude oil prices. The reduction was partly offset by higher inventory levels and lower accounts payable and accruals, reflecting completion of Project Millennium, offset partially by an increase in current liabilities resulting from recognition of the estimated employee long-term compensation program payment.

Capital investment at Oil Sands decreased to approximately $1.5 billion in 2001 from approximately $1.7 billion in 2000. The $239 million decrease was primarily due to lower spending on Project Millennium.

These combined factors resulted in a decrease in net cash deficiency from $1.2 billion in 2000 to approximately $1 billion in 2001.

Operating Margins
(Cdn$ per barrel)

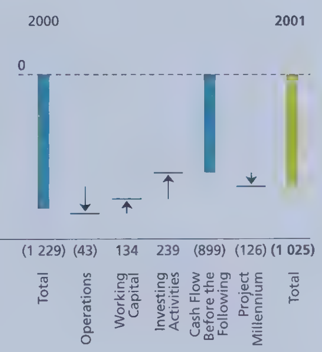


	1997	1998	1999	2000	**2001**
■ Selling Price	26.36	22.18	23.84	31.67	**29.17**
● Cash Margin	12.05	9.25	10.75	15.80-16.80	**11.50-16.60**

Selling price – The average price from the sale of crude oil, including the impact of hedging activities.

Cash margin – The difference between the selling price received for products sold and cash operating cost per barrel plus royalties per barrel.

Bridge Analysis of Net Cash Deficiency
(Cdn$ millions)



Lower capital spending on Project Millennium and a decrease in working capital mainly due to lower trade receivables were partially offset by decreased cash flow from operations and expenses associated with start-up of Project Millennium.

outlook

The foundation of Oil Sands growth plans is the large resource base estimated to be in place on Suncor leases.

Independent estimates place total Oil Sands resources at 12 billion barrels, including **proved and probable reserves** that are estimated at 4.4 billion barrels.

Suncor's future plans for Oil Sands are a continuation of the company's current plans and strategic drivers. The company's focus remains on activities expected to increase production, decrease operating costs and improve environment, health and safety performance.

Increase Production

Oil Sands expects production to average approximately 210,000 bpd in 2002 as the new Millennium facilities are fully integrated with base operations. This production goal assumes a 28-day maintenance shutdown will take place during the year. Management will look at the potential to defer the shutdown to 2003.

Construction on the first phase of the Firebag In-situ Oil Sands Project, including approved upgrader expansions, is scheduled to continue in 2002. Twenty steam assisted gravity drainage (SAGD) well pairs for Stage 1 are scheduled for drilling during the year. Production facility modules are under construction and installation is scheduled to begin at the site in the second quarter of 2002. Spending in 2002 for this work is currently estimated at $420 million. In-situ production from the first phase of Firebag and upgrader expansions is expected to bring Oil Sands production capacity from 225,000 bpd to a daily average of 260,000 bpd in 2005.

In 2002 Suncor will consult with stakeholders in creating detailed plans for engineering, design and project development for Project Voyageur. Voyageur is planned to further expand Suncor's oil sands and in-situ developments, building on the benefits of both types of operations to increase production.

Assuming production of 260,000 bpd has been reached by 2005, Voyageur phase one is being planned to increase production capacity to the range of 400,000 to 450,000 bpd in 2008. Current phase two plans call for additional processing units to reach a target production capacity of 500,000 to 550,000 bpd in 2010 to 2012.

Preliminary cost estimates for Voyageur will be made late in 2002. Development requires regulatory approval, and is subject to other conditions mentioned on page 30.

A Sustainability Legacy program will be integrated into planning for Voyageur with an objective of mitigating increases in air emissions, reducing water use and discharge, accelerating reclamation and limiting land disturbance. The Sustainability Legacy program also plans to examine ways Suncor can support training and apprenticeship programs and help neighbouring communities benefit from the growth of the oil sands industry. Currently, there are no cost estimates for this program.

Reduce Operating Costs

Management believes that debottlenecking and efficiency and reliability improvements provide an opportunity to further reduce the cash operating cost per barrel. Management will work towards its objective of achieving cash operating costs of $8.50 to $9.50 (approximately US$6) per barrel, though

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proved and probable reserves

Annual estimates are made by Suncor of recoverable bitumen reserves associated with company in-situ leases and of synthetic crude oil reserves associated with its mineable oil sands leases. The estimates are then allocated between proved and probable categories based upon criteria determined by management and reviewed by independent consultants. With proved reserves there is at least a 90% confidence the estimate will be exceeded.

Probable reserves incorporate portions of both mining and in-situ (Firebag) Suncor leases that have a lower drilling density and are expected to be recovered under current approvals within a period of 30 years. There is at least a 50% chance the proved plus probable reserve estimates will be exceeded. The bitumen estimates are converted to crude oil estimates on the basis of yields currently being obtained.

Resources include proved and probable reserves. These resources include quantities of oil and gas that are estimated, on a given date, to be potentially recoverable from known accumulations and undiscovered accumulations that are not proved or probable reserves. Resources are a higher risk and are generally believed to be less likely to be recovered than proved and probable reserves. Total resources include both synthetic crude oil estimates for mining leases, and bitumen estimates for in-situ oil sands leases.

attaining this objective will require achieving some of the improvements noted above and will depend on factors and assumptions such as natural gas costs at mid-cycle prices and higher production levels. In 2002 management believes cash operating costs could be in the $10 to $10.50 (US$6.50 to US$6.80) per barrel range.

These targets and estimates are subject to certain risk factors and uncertainties discussed on page 44 under "Forward-looking Statement" and their achievement cannot be assured.

risk/success factors affecting performance

The strategic advantages of Oil Sands growth include:

- Economies of scale associated with higher levels of production from the existing Oil Sands infrastructure.
- Parallel processing in the extraction and upgrading processes provide flexibility to schedule periodic plant maintenance while continuing to generate production from the remaining units.
- The ability to leverage demonstrated operational experience and technologies.
- Production growth without the level of exploration risk associated with conventional oil and gas operations.

The issues Suncor must manage include, but are not limited to:

- Suncor's ability to finance Oil Sands growth in a volatile commodity pricing environment. (Also refer to the section on Liquidity and Capital Resources on page 28.)
- The ability to complete future oil sands projects both on time and on budget could be impacted by competition from other oil sands projects for skilled people, increased demands on the Fort McMurray, Alberta infrastructure (housing, roads, schools, etc.), or higher prices for the products and services required to operate and maintain the Oil Sands plant. Suncor continues to address these issues through a comprehensive recruitment and retention strategy, working with the community to determine infrastructure needs, designing Oil Sands expansion to reduce unit costs, seeking strategic alliances with service providers and tightening controls on engineering, procurement and project management.
- Potential changes in the demand for refinery feedstocks and diesel fuel. Suncor believes it can reduce the impact of this issue by entering into long-term supply agreements with major customers, expanding its customer base and offering customized blends of refinery feedstocks to meet customer specifications.

The profitability of Suncor's Oil Sands business is influenced by world crude oil price levels. These prices are difficult to predict and impossible to control. In addition, the light/heavy oil differential can have an impact on earnings. In 2001, this differential widened and reduced earnings. Management believes the differential will trend toward more historical ranges in 2002 if the demand for heavy oil increases as anticipated.

Unplanned production or operational outages and slowdowns, particularly those that are weather-related, can be expected.

Suncor's relationship with employees and trade unions is important to the company's future success because work disruptions have the potential to adversely affect Oil Sands operations and growth projects. Suncor entered into a new three-year collective agreement with the Communications, Energy and Paperworkers Union, Local 707 effective May 1, 2001.

Also refer to Risk/Success Factors Affecting Performance on page 27.

Natural Gas overview

Suncor's Natural Gas business (NG) produces conventional natural gas in Western Canada, supplying it to markets throughout North America. The sale of NG production provides an internal hedge for Suncor's natural gas consumption.

In 2001, NG continued to advance its strategy for profitable growth in order to maintain an **internal hedge** for Suncor's growing gas consumption. This strategy is built on four key platforms:

- Focusing on natural gas.
- Building competitive operating areas.
- Improving base business efficiency.
- Creating new low capital service offerings to the resource sector.

NG's first service offering, Prospect Generation Services (PGS), was launched and generated net cash flow of $6 million in 2001 primarily through land sales. PGS develops prospects on new and existing non-core Suncor lands and markets those business opportunities to the resource sector. PGS earnings did not have a material impact on earnings in 2001.

net earnings analysis

Net Earnings Increase by 19%

Net earnings were $117 million in 2001, up 19% over the 2000 level of $98 million, primarily due to stronger natural gas prices and cost reductions. Operational earnings, which in 2001 exclude the impact of the adjustment related to revaluation of opening future provincial income tax balances ($9 million), asset divestments ($4 million) and restructuring charges ($1 million), increased by 75% from $59 million in 2000 to $103 million in 2001. This was primarily due to higher commodity prices and lower exploration and operating costs, partially offset by lower production volumes resulting from property divestments in 2000 and higher royalty expenses. Cash flow from operations rose to $280 million from $238 million in 2000, also a reflection of higher natural gas prices and lower costs.

results of operations, investing and exploration activities

2001 vs. 2000

Natural Gas – Summary of Results

($ millions unless otherwise noted)	2001	2000	1999
Revenue	**449**	428	306
Production (thousands boe/d)	**33.4**	40.5	51.1
Average sales price			
Natural gas ($/thousand cubic feet)	**6.09**	4.72	2.44
Natural gas liquids ($/barrel)	**34.38**	36.66	19.32
Crude oil ($/barrel)	**33.92**	29.50	20.94
Operational earnings	**103**	59	22
Net earnings	**117**	98	41
Cash flow provided from operations	**280**	238	172
Total assets	**722**	762	962
Capital and exploration expenditures	**132**	127	200
ROCE (%)	**32.1**	17.2	5.5

In 2001, Suncor began to convert natural gas to barrels of oil equivalent (boe) at a 6:1 ratio (thousand cubic feet of natural gas:barrel of oil); previously, conversion was on a 10:1 basis. Figures for 1999 and 2000 have been restated on a 6:1 basis.

internal hedge

An internal hedge occurs when Suncor's natural gas production equals or is greater than internal consumption, providing the company protection from volatile natural gas prices in the North American market.

Natural Gas Prices Increase 29%

In 2001, NG's natural gas price averaged $6.09 per thousand cubic feet (mcf) of natural gas, compared with $4.72 per mcf in 2000. Increased prices in 2001 were a result of increased demand coupled with a relatively flat natural gas supply in North American markets. NG also benefited from higher than industry average exposure to the high value California market in 2001. While crude oil made up only 7% of NG's production in 2001, crude prices were also higher than 2000, averaging $33.92 per barrel (after hedging losses), compared to $29.50 per barrel (after hedging losses) in 2000. The price for natural gas liquids averaged $34.38 per barrel in 2001, compared to $36.66 per barrel in 2000. The combined impact of the above pricing factors increased earnings by $49 million.

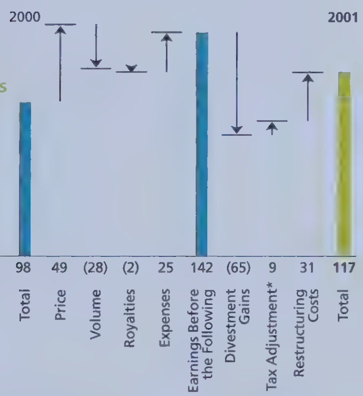
Production Declines 17% from 2000 Levels

NG's natural gas and liquids volumes declined to an average of 33,400 barrels of oil equivalent per day (boe/d), or 200 million cubic feet equivalent/day (mmcfe/d) in 2001, from an average of 40,500 boe/d or 243 mmcfe/d in 2000. The main reason for production declines was asset divestments associated with portfolio optimization during 2000. Production divestments of 10,600 boe/d at the time of sale were only partially offset by volume growth related to the 2001 capital spending program. The decrease in volumes resulted in a reduction in earnings of $28 million compared to 2000.

Royalties Increase

Royalties increased to $8.56 per boe in 2001, from $6.81 per boe in 2000 due mainly to the increase in commodity prices. The increase in royalties resulted in a reduction in earnings of $2 million.

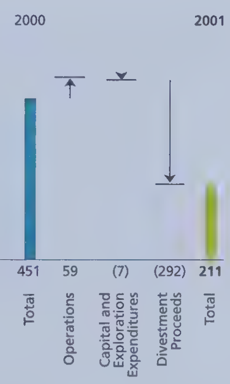
Bridge Analysis of Net Earnings
(Cdn$ millions)



Higher natural gas prices and lower expenses offset the decline in production from 2000 divestments.

* Provincial income tax rate adjustment on opening future tax balances.

Bridge Analysis of Net Cash Surplus
(Cdn$ millions)



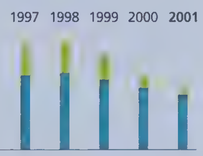
Year-over-year decline of $240 million in NG's net cash flow reflected lower proceeds from property dispositions and slightly higher capital and exploration spending, partially offset by higher operating cash flows resulting from higher natural gas prices and lower expenses.

Suncor NG Pricing vs. Industry Average
(Cdn$/thousand cubic feet)

	1997	1998	1999	2000	2001
Suncor NG Average Annual Price	1.93	1.95	2.44	4.72	**6.09**
Industry Average Reference Price	1.98	1.95	2.47	4.53	**5.39**

2001 Industry Average Reference Price is an estimate.

Production
(thousands of boe per day)



	1997	1998	1999	2000	2001
Natural Gas	40.0	41.2	37.7	33.3	**29.5**
Liquids (natural gas liquids and crude oil)	15.7	16.3	13.4	7.2	**3.9**
Total	55.7	57.5	51.1	40.5	**33.4**

Although 2001 production was lower than 2000 due to property divestments, production exceeded 2001 goals by 1,000 boe/d, as NG continued bringing non-producing reserves to the producing stage.

Total Expenses Reduced from 2000 Levels

Total expenses, excluding royalties and restructuring charges, were reduced by $49 million in 2001 from 2000 levels. Exploration expenses were down $31 million in 2001 due to a decrease in dry hole costs. Operating expenses decreased by $10 million compared to 2000 levels due to asset divestments and improved base business efficiency. Non-cash expenses (depreciation, depletion and amortization) decreased by $8 million as a result of divestments in 2000. Combined, the above factors increased earnings by $25 million year-over-year.

In 2000, NG set a target to decrease annualized operating costs by a total of $18 million to $20 million by year-end 2001. Approximately $15 million of this target was reached in 2000. Annualized operating costs decreased an additional $5 million in 2001 through a focus on administrative cost controls and reduced lifting costs.

Asset Divestment Gains

In 2001, NG divested a non-core heavy oil property, recording a $4 million after-tax gain, compared to a $69 million gain in 2000 when the majority of NG's announced strategic divestments occurred. This resulted in a $65 million change year-over-year.

Restructuring Charges

In 2001, NG recorded a positive adjustment on restructuring charges that increased after-tax earnings by $1 million. In 2000, NG recorded restructuring charges that reduced after-tax earnings by $30 million for a year-over-year change of $31 million.

Tax Adjustments

In 2001, earnings benefited from positive tax adjustments of $9 million. This reflects the impact of adjustments related to revaluation of opening future income tax balances.

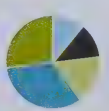
Net Cash Surplus Analysis

NG had a net cash surplus of $211 million in 2001, a decline of $240 million when compared to the net cash surplus of $451 million in 2000. This reduction was primarily due to a decrease in divestment proceeds of $292 million, partially offset by an improvement in cash from operating activities of $59 million.

Capital and Exploration Investing Analysis

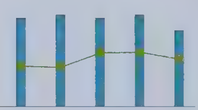
During 2001, NG continued to focus on bringing proved undeveloped reserves into production. Capital expenditures were $132 million, higher than $127 million in 2000, due to increased expenditures on coalbed methane land acquisition and exploration. Divestment proceeds decreased $292 million as a result of completing the strategic divestment program in 2000.

2001 Direct Proprietary Gas Sales
(69% of sales)



	(mmcf/d)	(%)
British Columbia	13	11
Midwest U.S.	15	12
Eastern Canada	21	17
California	40	33
Alberta	33	27
Total	122	100

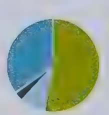
Lifting and Administration Costs



	1997	1998	1999	2000	**2001**
Administration (Cdn$ millions)	28	29	28	29	**24**
Lifting ($ per boe)	2.81	2.79	3.10	3.11	**2.96**

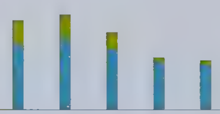
Total operating costs decreased from the prior year as Natural Gas maintained focus on controlling administrative costs and reducing lifting costs.

2001 System Proprietary Gas
(31% of sales)



	(mmcf/d)	(%)
TransCanada Gas Services	29	53
Pan Alberta	19	35
Canwest	2	3
Other	5	9
Total	55	100

Total Proved Reserves
(millions of barrels of oil equivalent)



	1997	1998	1999	2000	**2001**
Natural Gas	182	200	168	133	**125**
Liquids	70	69	51	16	**14**
Total	252	269	219	149	**139**

Over the last two years, Natural Gas activities have been directed towards bringing non-producing reserves to the producing stage.

outlook

Profitable Growth

NG has a goal of achieving a return on capital employed (after-tax earnings divided by average capital employed) of at least 12% in 2002 and 15% in 2004 at mid-cycle natural gas prices (US$3.00 to US$3.50/mcf price range) while producing volumes in excess of internal demand. Management will work toward this goal by building existing operating areas and developing new production and revenue streams.

NG's production outlook for 2002 targets 180 mmcf/d to 190 mmcf/d of natural gas plus 1,800 bpd of natural gas liquids and 1,200 bpd of oil.

Leveraging Suncor's expertise and assets in three core areas in western Alberta and northeastern British Columbia will continue to be the foundation for production and revenue in 2002.

Sustainability and Renewable Energy

Suncor announced plans to place investments in renewable energy under the management of NG beginning in 2002. NG will manage and operate Suncor's renewable energy projects, but segmented financial data will be reported under Corporate results. This realignment is part of Suncor's strategy to provide hydrocarbon-based resources that meet the immediate energy needs of consumers while also pursuing the development of low-emission and no-emission energy sources that have a reduced environmental impact.

In 2002, Suncor plans to continue to investigate wind power as an economically viable source of renewable energy. Incentives announced in Canada's federal budget late in 2001 should increase the attractiveness of wind power investments.

Coalbed methane development may contribute to both increased volumes and reduced carbon dioxide (CO_2) emissions. NG is participating in research and development initiatives to evaluate the potential of coalbeds to **sequester** CO_2, a waste greenhouse gas emission. CO_2 pumped into the coalbed may provide an economic means of increasing production of natural gas from the coalbed while reducing the company's net overall greenhouse gas emissions.

risk/success factors affecting performance

Management continues to believe the single most important factor influencing NG's long-term performance is its ability to consistently and competitively find and develop reserves that can be brought on stream economically. Market demand for land and services can also increase or decrease operating costs.

Management believes there are risks and uncertainties associated with obtaining regulatory approval for exploration and development activities. Working in other countries could increase these risks and add to costs or cause delays to these projects.

These factors and estimates are subject to certain of the risks, assumptions and uncertainties discussed on page 44 under "Forward-looking Statement" and their achievement cannot be assured.

Also refer to Risk/Success Factors Affecting Performance on page 27.

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sequester
Sequester refers to the capture and storage of carbon dioxide, preventing its release to the atmosphere.

Sunoco overview

Suncor's wholly owned subsidiary Sunoco Inc. operates a refining and marketing business in central Canada. Its Sarnia, Ontario refinery has the capacity to refine 70,000 barrels per day of crude oil into gasoline, distillates and petrochemical products. Products are sold to wholesale, commercial and industrial markets and through a controlled retail network in Ontario.

Sunoco's refining and marketing strategy is focused on:

- Improving gross profit of refining assets.
- Enhancing retail customer offering.
- Creating long-term growth opportunities.
- Supporting sustainable development.

For the third consecutive year, Sunoco continued to show volume growth in refined product sales. In 2001, total sales averaged 93,400 barrels per day (bpd), representing an improvement of 1% from 2000. Sunoco's share of the total refined product sales in its primary market of Ontario was approximately 18%, compared to 17% in 2000.

Approximately 59% of Sunoco's total sales volumes are marketed in Ontario through controlled retail networks. These include 302 Sunoco retail service stations, 18 Sunoco-branded Fleet Fuel Cardlock sites and two joint venture businesses comprised of 154 Pioneer-operated service stations, 47 UPI-operated retail service stations and bulk distribution facilities for rural and farm fuels. (Pioneer Group Inc. is an independent retailer with which Sunoco has a 50% joint venture partnership and UPI Inc. is a 50% joint venture company with GROWMARK Inc.)

Approximately 38% of Sunoco's refined products were sold to wholesale and industrial accounts in Ontario and Quebec in 2001, primarily consisting of jet fuels, diesel and gasolines. The remaining 3% of Sunoco's refined products were petrochemicals sold through Sun Petrochemicals Company, a 50% joint venture between a subsidiary of Sunoco and a U.S. refinery. Sunoco also markets natural gas to approximately 125,000 commercial and residential customer accounts in Ontario.

results of operations and investing activities

2001 vs. 2000

Sunoco – Summary of Results

($ millions unless otherwise noted)	**2001**	2000	1999
Revenue	**2 588**	2 604	1 779
Refined product sales			
(thousands of cubic metres)			
Sunoco retail gasoline	**1 575**	1 539	1 500
Total	**5 419**	5 360	5 080
Operational earnings	**70**	68	27
Net earnings (loss) breakdown:			
Rack Back	**47**	69	14
Rack Forward	**23**	(1)	13
Others (tax adjustments)	**10**	13	—
Total	**80**	81	27
Cash flow provided			
from operations	**165**	174	103
Investing activities	**71**	59	43
Net cash surplus	**111**	155	129
ROCE (%)	**18.4**	20.5	6.0

In January 2002, Suncor's downstream operations were reorganized as Energy Marketing and Refining. Segmented results for 2001 are reported under the Sunoco name.

net earnings analysis

Net Earnings Remain Steady

Sunoco's 2001 net earnings were $80 million, compared with $81 million in 2000. Operational earnings were $70 million, up from $68 million in 2000. Operational earnings in 2001 and 2000 exclude favourable income tax adjustments of $10 million and $13 million, respectively, related to revaluation of opening future provincial income tax balances. The higher operational earnings were due primarily to improved margins in the commercial and reseller channels, stronger profit from retail operations and retail natural gas business, and a 1% growth in sales volumes. Partially offsetting the favourable factors were lower refining margins, lower refinery production and higher expenses. Return on capital employed was 18.4%, compared to 20.5% in 2000. The reduction resulted from lower net earnings combined with a higher capital employed.

Lower Refining Margins Impact Rack Back

Rack back operational earnings declined to $47 million in 2001, compared with $69 million in 2000, due primarily to lower refining margins, lower refinery production and higher expenses. Refining margins decreased to 5.7 cents per litre (cpl) in 2001, compared with 5.9 cpl in 2000. The lower margins were attributable to a decline in product demand resulting from a weakening economy. Net earnings decreased by $14 million due to lower refining margins and higher costs driven by increased product purchases.

The refinery encountered a number of unplanned outages involving the catalytic cracker (in the first quarter, 2001) and the petrochemical and vacuum units (in the fourth quarter, 2001). As a result, the crude utilization rate dropped to 92%, down 6% from 2000. Additional product purchases were made to satisfy customer demand due to the lower production.

Sales volumes were 1% higher compared to 2000, averaging 14,800 cubic metres per day (93,400 bpd) from 14,600 cubic metres per day (92,200 bpd) in 2000. The higher sales volumes were comprised of the refinery's production, which was 4% lower than 2000, and purchases of finished products to meet customer demand.

In the fourth quarter of 2001, the Sarnia refinery completed a planned maintenance shutdown. While a majority of the work was completed on schedule, there was a two-week extension to resolve catalyst problems.

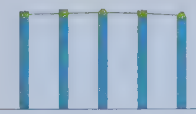
Rack Back's expenses were $22 million higher in 2001 compared with 2000, primarily as a result of higher natural gas prices and a 20% increase in natural gas consumption due to reduced fuel oil burning. The increase in expenses was partially offset by a gain of $9 million in 2001 from sales of excess supplies of natural gas initially bought for the retail natural gas marketing business. Due to changes in customer demand forecasting methodology, excess gas supply was identified and liquidated.

Also impacting Rack Back's earnings was a $2 million earnings reduction from Sun Petrochemicals Company.

Rack Forward Earnings Up $24 Million

Rack forward operational earnings increased to $23 million in 2001, compared to a loss of $1 million in 2000. The increase was attributable to stronger earnings from retail operations, commercial and reseller channels and improved retail natural gas margins.

**Crude Utilization/
High Value Components**
(percentage)



	1997	1998	1999	2000	**2001**
■ Crude Utilization	97	99	95	98	**92**
● High Value Components	90	91	92	91	**89**

Sunoco's crude utilization rate declined 6% to 92% in 2001 due primarily to unplanned outages during the year. A planned maintenance shutdown was also completed in the fourth quarter.

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rack back and rack forward

Sunoco's financial reporting in 2001 is based on its Rack Back/Rack Forward organizational structure and prior year results have been reclassified accordingly. The Rack Back division includes the procurement and refining of crude oil and feedstocks and sales and distribution to the Sarnia refinery's largest industrial and reseller customers. Rack Forward includes retail operations, retail natural gas marketing, cardlock and industrial/commercial sales, and the UPI and Pioneer joint venture businesses.

For the fourth consecutive year, gasoline sales at Sunoco's retail network increased. Retail gasoline volume improved by more than 2%, contributing to an earnings improvement of $2 million over 2000. While the retail gasoline margin remained unchanged from 2000 at 6.6 cpl in 2001, total fuel margins from the retail business improved by $4 million due to a more favourable product mix. **Ancillary** and royalty income was $4 million higher than 2000, reflecting continued expansion of non-fuel products and services in the retail network. These positive earnings impacts were partially offset by increased expenses of $7 million resulting from higher operating costs.

In 2001, retail natural gas margins improved $10 million from 2000. The restructuring of customer contracts enabled Sunoco to match fixed price sales contracts with fixed price supply. In addition, commercial and reseller sales channels further improved Rack Forward earnings by $8 million due to margin improvement and $1 million related to volume growth.

Net earnings from Sunoco's retail joint ventures with UPI and Pioneer were $2 million higher in 2001, reflecting stronger volumes and margins.

Net Cash Surplus Analysis

Net cash surplus decreased to $111 million in 2001, compared with $155 million in 2000. This decrease reflects the higher investment spending of $12 million, a lower working capital decline of $23 million compared to 2000 and a decrease in cash flow provided from operations of $9 million. This decrease includes the recognition of estimated payments in 2002 with respect to Suncor's employee long-term compensation programs.

Working capital decreased by $17 million in 2001, compared with a reduction of $40 million in 2000, contributing $23 million to the net cash surplus decline. Key contributing factors were higher ending inventory and lower product prices impacting payables. Investing activities totalled $71 million in 2001, including $9 million for the planned maintenance shutdown at the Sarnia refinery, compared with $59 million in 2000.

outlook

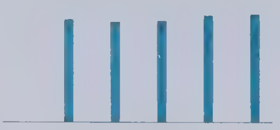
Sunoco will continue to focus on improving gross profit of refining assets, enhancing its retail customer offerings, creating long-term growth opportunities and focusing on sustainable development.

Improve Gross Profit of Refining Assets

Sunoco continues to pursue its goal to position the Sarnia refinery in the top one-third of North American refineries of similar size and complexity by the end of 2002. To achieve this, Sunoco will continue to focus on increasing the operational flexibility of the Sarnia refinery to run different feedstocks, improving energy cost management and optimizing existing assets to improve reliability and flexibility.

To reduce exposure to energy cost increases, an energy supply agreement was signed with TransAlta Energy Corporation (TransAlta) in 2001. Under the contract, the TransAlta Sarnia Regional Cogeneration Project will provide a portion of its steam supply to the Sarnia refinery at a competitive cost, eliminating the need for Sunoco to build boilers for steam generation. According to TransAlta, the new facility is expected to commence operation in late 2002.

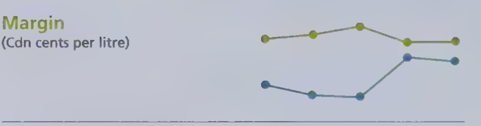
Refined Product Sales Volumes
(thousands of cubic metres)



1997	1998	1999	2000	**2001**
5 182	5 037	5 080	5 360	**5 419**

Total sales volumes increased by more than 1% over 2000, reflecting higher commercial/industrial sales volume and continued volume growth in the retail gasoline business.

Margin
(Cdn cents per litre)



	1997	1998	1999	2000	**2001**
● Sunoco-branded Retail Gasoline Margin	6.8	7.0	7.4	6.6	**6.6**
● Refining Margin	4.6	4.1	4.0	5.9	**5.7**

Refining margins declined from last year due mainly to the higher industry inventory levels and lower demand in North America. Sunoco retail gasoline margins remained unchanged from last year.

ancillary income
Income earned from non-fuel products and services such as car washes, sale of fast foods and confectionery items.

Enhance Retail Customer Offerings

Sunoco plans to implement initiatives to improve its retail customer offerings by expanding premium food and beverage service. Sunoco also continues to expand its premium fuel products to retail customers. Marketing initiatives are in place to increase sales of premium fuel products such as Ultra 94 gasoline and Gold Diesel.

Create Long-Term Growth Opportunities

Sunoco continues to evaluate strategic opportunities associated with the industry's need to reformulate fuels to comply with new sulphur regulations on gasoline and diesel.

Integration enhancement with Oil Sands and the economic attractiveness of processing sour streams continue to be a strategic focus. To capture a greater share of long-term value from increasing Oil Sands production, Sunoco will continue to assess new marketing and refining investment opportunities to further integrate Suncor's upstream and downstream businesses.

Sunoco completed a strategic assessment in 2001 of its retail natural gas marketing business and is exploring possible disposition, joint venture or other transactions.

Focus on Sustainable Development

Sunoco completed a detailed emission reduction plan in 2001. The plan targets to reduce emissions of carbon dioxide, sulphur dioxide, nitrogen oxide and volatile organic compounds at the Sarnia refinery by 25% from the 1995 levels by 2005.

While targeting improved margins and market growth, Sunoco also continues to focus on environmental issues facing Ontario and Canada and developing more environmentally responsible products. For example, to reduce emissions of carbon monoxide and greenhouse gas, Sunoco's retail network introduced ethanol-enhanced gasoline in 1997, which is now blended in all Sunoco gasoline and marketed through the Sunoco, UPI and Pioneer retail networks.

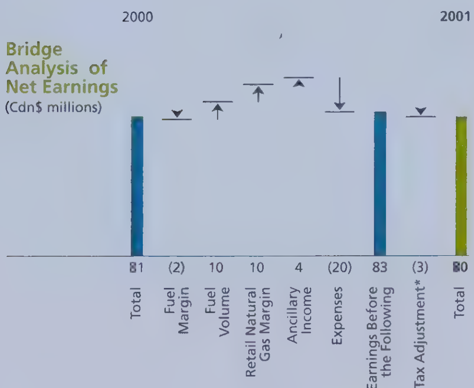
Sunoco will continue to enforce management control programs to improve health and safety performance.

risk/success factors affecting performance

While Suncor's downstream business achieved higher operational earnings in 2001, financial performance in the second half of the year was negatively affected by margin and crude oil price volatility, lower demand for energy products and overall market competitiveness. Management expects fluctuation in demand for refined products, margin and price volatility and market competitiveness will continue to impact the business environment.

The Canadian refining industry faces significant capital spending to construct sulphur removal facilities. The spending is required to comply with legislation limiting sulphur levels in gasoline to an average of 150 parts per million (ppm) from mid-2002 to the end of 2004 and a maximum of 30 ppm by 2005. In 2001, Sunoco finalized an investment plan to meet the sulphur content limits. Capital spending

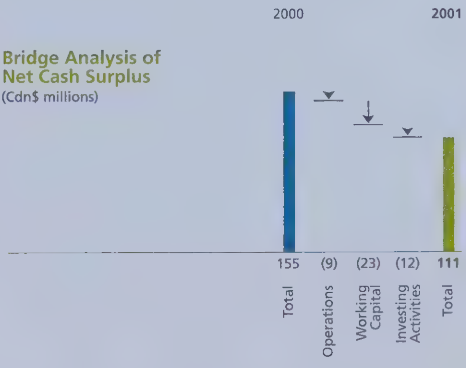
Bridge Analysis of Net Earnings
(Cdn$ millions)



Improvement in fuel volume, natural gas margin and ancillary income helped offset increased expenses and lower margins. Tax adjustments related to opening future income tax balances were $3 million lower than in 2000.

* Provincial income tax rate adjustment on opening future tax balances.

Bridge Analysis of Net Cash Surplus
(Cdn$ millions)



Net cash surplus declined $44 million to $111 million in 2001 due to a combination of higher capital spending and lower reduction in working capital driven by higher inventory and lower accounts payable.

to achieve compliance is expected to be approximately $40 million and will involve the addition of a new desulphurization unit. Construction is expected to be completed in 2003. In 2001 Sunoco's sulphur level in gasoline averaged about 180 ppm, compared with the 2000 Ontario industry average of 450 ppm.

Environment Canada is expected to finalize new on-road diesel sulphur regulations by mid-2002, with an implementation date of mid-2006. Regulations reducing sulphur in off-road diesel and light fuel oil are also expected. Sunoco continues to examine strategic options to comply with the pending regulations. Actual capital spending required to meet the new standard is subject to the development of such regulations and strategic assessment. Capital spending could be significant, but is not expected to place the company at a competitive disadvantage.

These factors and estimates are subject to certain of the risks, assumptions and uncertainties discussed below under "Forward-looking Statement" and their achievement cannot be assured.

Also refer to Risk/Success Factors Affecting Performance on page 27.

Forward-looking Statement

This Management's Discussion and Analysis contains certain forward-looking statements that are based on Suncor's current expectations, estimates, projections and assumptions and were made by the company in light of its experience and its perception of historical trends.

All statements that address expectations or projections about the future, including statements about Suncor's strategy for growth, expected and future expenditures, commodity prices, costs, schedules and production volumes, operating and financial results, are forward-looking statements. Some of the forward-looking statements may be identified by words like 'expects,' 'anticipates,' 'plans,' 'intends,' 'believes,' 'projects,' 'indicates,' 'could,' 'vision,' 'goal,' 'target,' 'objective' and similar expressions. These statements are not guarantees of future performance and involve a number of risks, uncertainties and assumptions. Suncor's business is subject to risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to Suncor. Suncor's actual results may differ materially from those expressed or implied by its forward-looking statements as a result of known and unknown risks, uncertainties and other factors.

The risks, uncertainties and other factors that could influence actual results include: changes in the general economic, market and business conditions; fluctuations in supply and demand for Suncor's products; fluctuations in commodity prices; fluctuations in currency exchange rates; Suncor's ability to respond to changing markets; the ability of Suncor to receive timely regulatory approvals; the successful implementation of its growth projects including the Firebag In-situ Oil Sands Project and Project Voyageur; the integrity and reliability of Suncor's capital assets; the cumulative impact of other resource development projects; Suncor's ability to comply with current and future environmental laws; the accuracy of Suncor's production estimates and production levels and its success at exploration and development drilling and related activities; the maintenance of satisfactory relationships with unions, employee associations and joint venturers; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; the uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures; actions by governmental authorities including increasing taxes, government fees, changes in environmental and other regulations; the ability and willingness of parties with whom Suncor has material relationships to perform their obligations to Suncor; and the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor. Many of these risk factors are discussed in further detail throughout this Management's Discussion and Analysis and in the company's Annual Information Form on file with the Alberta Securities Commission and certain other securities regulatory authorities. Readers are also referred to the risk factors described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

The tables and charts in this document form an integral part of Management's Discussion and Analysis and should be referred to when reading the narrative. References to Suncor or the company include Suncor Energy Inc. and its subsidiaries and investment in joint ventures, unless otherwise stated.

management's statement on financial reporting

The financial statements on pages 46 to 68, which consolidate the financial results of Suncor Energy Inc., its subsidiaries and joint ventures, and all information in this annual report, are the responsibility of management.

The financial statements have been prepared in accordance with Canadian generally accepted accounting principles. They include some amounts that are based on estimates and judgments relating to matters not concluded by year-end. Financial information presented elsewhere in this annual report is consistent with that in the financial statements.

In management's opinion the financial statements have been properly prepared within reasonable limits of materiality and within the framework of the accounting policies summarized on pages 46 to 48. In meeting its responsibilities for the integrity of the financial statements, management maintains a system of internal controls and an internal audit program. Management also administers a program of proper business conduct compliance.

PricewaterhouseCoopers LLP, the company's independent auditors, have audited the accompanying financial statements. Their report accompanies this statement.

The Audit Committee of the Board of Directors, composed of five independent directors, meets regularly with management, the internal auditors and PricewaterhouseCoopers LLP to review their activities and to discuss auditing, management information systems, internal control, accounting policy and financial reporting matters. The Audit Committee also meets quarterly to review and approve interim financial statements prior to release. The internal auditors and PricewaterhouseCoopers LLP have unrestricted access to the company, the Audit Committee and the Board of Directors. The Audit Committee reviews the financial statements and Management's Discussion and Analysis and recommends approval to the Board of Directors.

Rick George

Rick George
President and
Chief Executive Officer

Michael W. O'Brien

Mike O'Brien
Executive Vice President,
Corporate Development
and Chief Financial Officer

January 16, 2002

auditors' report

To the Shareholders of Suncor Energy Inc.

We have audited the consolidated balance sheets of Suncor Energy Inc. as at December 31, 2001, 2000 and 1999 and the consolidated statements of earnings, cash flows and changes in shareholders' equity for each of the years then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in Canada. Those standards require that we plan and perform an audit to obtain reasonable assurance that the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2001, 2000 and 1999 and the results of its operations and cash flows for each of the years then ended in accordance with accounting principles generally accepted in Canada.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
January 16, 2002

Suncor Energy Inc. is an integrated Canadian energy company, comprised of three operating segments: Oil Sands, Natural Gas and Sunoco.

Oil Sands includes the production of light sweet and light sour crude oil, diesel fuel and various custom blends from oil sands mined in the Athabasca region of northeastern Alberta, and the marketing of these products in Canada and the United States.

Natural Gas includes the exploration, acquisition, development, production, transportation and marketing of natural gas and crude oil in Canada and the United States.

Sunoco includes the manufacture, transportation and marketing of petroleum and petrochemical products, primarily in Ontario and Quebec, and the marketing of natural gas in Ontario. Petrochemical products are also sold in the United States and Europe.

The significant accounting policies of the company are summarized below:

(a) Principles of Consolidation and the Preparation of Financial Statements

These consolidated financial statements are prepared and reported in Canadian dollars in accordance with Canadian generally accepted accounting principles (GAAP), which differ in some respects from GAAP in the United States. The significant differences in GAAP, as applicable to these consolidated financial statements and notes, are described in the company's annual report on Form 40-F, which is filed with the United States Securities and Exchange Commission and is available on request.

The consolidated financial statements include the accounts of Suncor Energy Inc. and its subsidiaries and the company's proportionate share of the assets, liabilities, revenues, expenses and cash flows of its joint ventures.

The timely preparation of financial statements requires that management make estimates and assumptions, and use judgment, regarding assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

(b) Cash Equivalents and Investments

The company considers all highly liquid investments with a maturity of three months or less at the time of purchase to be cash equivalents. Cash equivalents consist primarily of term deposits and certificates of deposit. Investments with maturities from greater than three months to one year are classified as short-term investments, while those with maturities in excess of one year are classified as long-term investments. Cash equivalents and short-term investments are stated at cost, which approximates market value.

(c) Revenues

Crude oil sales from upstream operations (Oil Sands and Natural Gas) to downstream operations (Sunoco) are based upon actual product shipments. On consolidation, revenues from these sales are eliminated from sales and other operating revenues and purchases of crude oil and products.

The company also uses a portion of its natural gas production for internal consumption at its oil sands plant and refinery. On consolidation, revenues from these sales are eliminated from sales and other operating revenues and operating, selling and general expenses.

Revenues associated with sales of crude oil, natural gas, petroleum and petrochemical products and all other items not eliminated on consolidation are recorded when title passes to the customer. Revenues from natural gas production from properties in which the company has an interest with other producers are recognized on the basis of the company's net working interest.

(d) Property, Plant and Equipment

Cost

Property, plant and equipment are recorded at cost.

The company follows the successful efforts method of accounting for its crude oil and natural gas operations. Under the successful efforts method, acquisition costs of proved and unproved properties are capitalized. Costs of unproved properties are transferred to proved properties when proved reserves are confirmed. Exploration costs, including geological and geophysical costs, are expensed as incurred. Exploratory drilling costs are capitalized initially. If it is determined that the well does not contain proved reserves, the capitalized exploratory drilling costs are charged to expense, as dry hole costs, at that time. The related land costs are expensed through the amortization of unproved properties as covered under the Natural Gas section of the depreciation, depletion and amortization policy below.

Development costs, which include the costs of wellhead equipment, development drilling costs, gas plants and handling facilities, applicable geological and geophysical costs and the costs of acquiring or constructing support facilities and equipment are capitalized. Costs incurred to operate and maintain wells and equipment and to lift oil and gas to the surface are expensed as operating costs.

Interest Capitalization

Interest costs relating to major capital projects and to the portion of non-producing oil and gas properties expected to become producing are capitalized as part of the cost of such property, plant and equipment. Capitalization of interest ceases when the capital asset is substantially complete and ready for its intended productive use.

Leases

Leases entered into by the company as lessee that transfer substantially all the benefits and risks of ownership to the lessee are recorded as capital leases and classified as property, plant and equipment with offsetting long-term borrowings. All other leases are classified as operating leases under which leasing costs are expenses in the period in which they are incurred.

Gains and losses on the sale and leaseback of assets recorded as capital leases are deferred and amortized to earnings in proportion to the amortization of leased assets.

Depreciation, Depletion and Amortization

Oil Sands:

Property, plant and equipment are depreciated over their useful lives on a straight line basis, except for original lease acquisition costs and related mine assets, which are depreciated over the life of proved reserves on a unit of production basis.

The company is depreciating property, plant and equipment as follows:

i) mobile equipment over three to 20 years;

ii) mine equipment and acquisition costs of original lease over approximately four million barrels of proved reserves;

iii) plant and other property and equipment, including new leases, primarily over four to 40 years.

Natural Gas:

Unproved properties of which acquisition costs are individually significant are evaluated for impairment by management. Impairment of unproved properties of which acquisition costs are not individually significant is provided for through amortization of the portion not expected to become producing, based on historical experience, over the average projected holding period.

Acquisition costs of proved properties are depleted using the unit of production method based on proved reserves. Capitalized exploratory drilling costs and development costs are depleted on the basis of proved developed reserves. For purposes of the depletion calculation, production and reserves volumes for oil and natural gas are converted to a common unit of measure on the basis of their approximate relative energy content. Gas plants, support facilities and equipment are depreciated on a straight line basis over their useful lives, which average 12 years.

Sunoco:

Depreciation of property, plant and equipment is on a straight line basis over their useful lives. The refinery and additions thereto are depreciated over an average of 30 years, service stations and related equipment over an average of 20 years and other facilities and equipment over three to 25 years.

Reclamation and Environmental Remediation Costs

Reclamation and environmental remediation costs for identified sites are estimated and charged against earnings when there exists a regulatory or statutory requirement or contractual agreement, or when management has made a decision to decommission or restore a site, providing that assessments indicate that such costs are probable and reasonably estimable.

Estimated reclamation costs in the company's upstream operations are accrued on the unit of production basis. Estimated environmental remediation costs, which are predominantly in the company's downstream operations, are accrued for those sites where assessments indicate that such work is required.

Costs are accrued based upon currently known information, estimated timing of remedial actions, and existing regulatory requirements and technology. Changes in these factors may result in material changes to estimated costs, which will be recognized prospectively when known.

Impairment

Property, plant and equipment are reviewed for impairment whenever events or conditions indicate that their net carrying amount, less related provisions for reclamation and environmental remediation costs and future income taxes, may not be recoverable from estimated undiscounted future cash flows. If it is determined that the estimated net recoverable amount is less than the net carrying amount, then a write-down to the estimated net recoverable amount is made, with a charge to earnings.

Disposals

Gains or losses on disposals of property, plant and equipment are generally recognized in earnings. For oil and gas property, plant and equipment, gains or losses are recognized in earnings for significant disposals or disposal of an entire property. However, the acquisition cost of an unproved property surrendered or abandoned that is not individually significant or a partial abandonment of a proved property is charged to accumulated depreciation, depletion or amortization, as appropriate.

(e) Deferred Charges

Overburden removal costs incurred to expose oil sands for mining, including depreciation on overburden removal equipment where applicable, are deferred. These costs are amortized based on the amount of oil sands mined in the year, the ratio of total overburden to be removed to total reserves of oil sands to be mined and the removal cost, determined on a last-in, first-out (LIFO) basis, per unit of overburden.

The cost of major maintenance shutdowns is deferred and amortized on a straight line basis over the period to the next shutdown that varies from three to seven years. Normal maintenance and repair costs are charged to expense as incurred.

Goodwill is reviewed on an ongoing basis by management to determine if the unamortized goodwill balance can be recovered through undiscounted projected future operating cash flows. If it cannot be recovered, the goodwill is considered permanently impaired and the net book value of goodwill would be written down.

Oil Sands preproduction costs incurred at the inception of operation are amortized on a unit of production basis over the life of proved producing reserves.

(f) Employee Future Benefits

The company has employee future benefit programs as follows:

- Defined benefit pension plans and a defined contribution pension plan providing retirement benefits for its eligible employees, and supplementary defined benefit pension plans providing additional retirement benefits for its executives;
- Other post-retirement benefits, including certain health care and life insurance benefits, for its retired employees and eligible surviving dependants;
- Post-employment benefits providing certain benefits to former or inactive employees and eligible surviving dependants, after employment but before retirement under specified circumstances.

The estimated future cost of providing defined benefit pension and other post-retirement benefits is actuarially determined using management's best estimates of demographic and financial assumptions, and such cost is accrued rateably from the date of hire of the employee to the date the employee becomes fully eligible to receive the benefits. The discount rate used to determine accrued benefit obligations is based upon a year-end market rate of interest. Company contributions to the defined contribution plan are expensed as incurred.

(g) Inventories

Inventories of crude oil and refined products are valued at the lower of cost using the last-in, first-out (LIFO) method and net realizable value.

Materials and supplies are valued at the lower of average cost and net realizable value.

(h) Derivative Financial Instruments

The company periodically enters into derivative financial instrument contracts such as forwards, futures, swaps and options to hedge against the potential adverse impact of market prices for its petroleum and natural gas products and to protect its Canadian dollar income and cash flows against adverse foreign currency exchange movements. The company also periodically enters into derivative financial instrument contracts such as interest rate swaps as part of its risk management strategy to minimize exposure to interest rate fluctuations. The company does not use derivative financial instruments involving multipliers or leverage.

These derivative contracts are initiated within the guidelines of the company's risk management policies, which require stringent authorities for approval and commitment of contracts, designation of the contracts by management as hedges of the related transactions, and monitoring of the effectiveness of such contracts in reducing the related risks. Contract maturities are consistent with the settlement dates of the related hedged transactions.

Derivative contracts accounted for as hedges are not recognized in the consolidated balance sheets. Gains or losses on these contracts, including realized gains and losses on hedging derivative contracts settled prior to maturity, are recognized in earnings and cash flows when the related sales revenues, costs, interest expense and cash flows are recognized.

Gains or losses resulting from changes in the fair value of derivative contracts that do not qualify for hedge accounting are recognized in earnings and cash flows when those changes occur.

(i) Foreign Currency Translation

Monetary assets and liabilities in foreign currencies are translated to Canadian dollars at rates of exchange in effect at the end of the period. Other assets and related depreciation, depletion and amortization, other liabilities, revenues and expenses are translated at rates of exchange in effect at the respective transaction dates. The resulting exchange gains and losses are included in earnings, except for unrealized exchange gains and losses arising on translation of long-term liabilities with fixed or ascertainable lives. These gains and losses are deferred and amortized over the remaining terms of the liabilities.

The company's former Stuart Oil Shale Project in Australia was integrated with the company's other activities and was translated in the manner described above.

(j) Stock-based Compensation Plans

Under the company's share option programs, common share options are granted to executives, certain employees and non-employee directors. The company does not recognize compensation expense on the issuance of common share options under these programs because the exercise price of the share options is equal to the market value of the common shares at the date of grant.

The company also has long-term employee incentive plans that provide awards to certain executives based on the market price of the company's common shares and to all other employees based on the market price of the company's common shares and the achievement of certain performance measurement criteria relating to the company's business segments. These awards vest on April 1, 2002, and are payable at that time, generally in equal amounts of cash and common shares of the company. The estimated costs of the cash portion of these awards, based on share price and expected performance achievement, are recorded as compensation expense over the vesting period.

Under the company's directors' compensation plan, non-employee directors of the company may elect to receive half or all of their annual remuneration as directors in common share equivalents. The estimated costs of directors' compensation in the form of these common share equivalents, based on share price, are recorded as compensation expense annually.

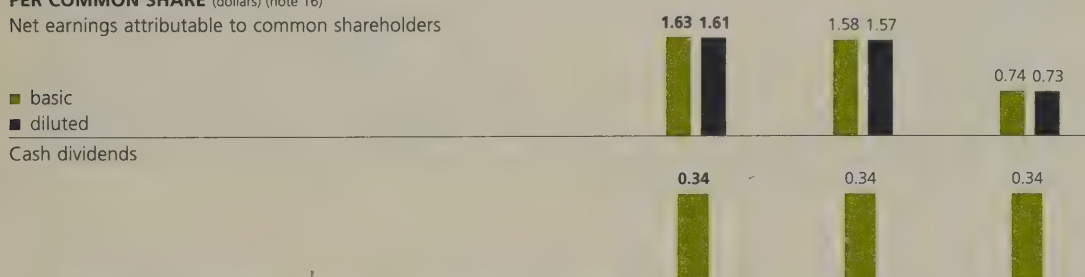
consolidated statements of earnings

for the years ended December 31

($ millions)	**2001**	2000	1999
REVENUES			
Sales and other operating revenues (notes 4, 6 and 18)	**3 990**	3 385	2 383
Interest	**5**	3	4
	3 995	3 388	2 387
EXPENSES			
Purchases of crude oil and products (note 18)	**1 391**	807	519
Operating, selling and general (note 12)	**1 010**	918	774
Exploration (note 4)	**22**	53	40
Royalties (note 3)	**134**	199	99
Taxes other than income taxes (note 4)	**367**	361	334
Depreciation, depletion and amortization	**360**	365	318
Gain on disposal of assets	**(7)**	(148)	(34)
Start-up expenses – Project Millennium (note 8)	**141**	15	—
Write-off of oil shale assets (note 1)	**48**	125	—
Restructuring (note 2)	**(2)**	65	—
Interest (note 4)	**18**	8	26
	3 482	2 768	2 076
EARNINGS BEFORE INCOME TAXES	**513**	620	311
Provision for income taxes (note 5)			
Current	**4**	45	29
Future	**121**	198	96
	125	243	125
NET EARNINGS	**388**	377	186
Dividends on preferred securities (note 15)	**(26)**	(26)	(22)
Net earnings attributable to common shareholders	**362**	351	164

PER COMMON SHARE (dollars) (note 16)

Net earnings attributable to common shareholders



See accompanying Summary of Significant Accounting Policies and notes.

consolidated balance sheets

as at December 31

($ millions)	2001	2000	1999
ASSETS			
Current assets			
Cash and cash equivalents	**1**	21	5
Accounts receivable (notes 4 and 6)	**306**	407	277
Income taxes recoverable	**28**	—	—
Future income taxes (note 5)	**29**	45	14
Inventories (note 7)	**258**	192	161
Total current assets	**622**	665	457
Property, plant and equipment, net (note 8)	**7 141**	5 883	4 528
Deferred charges and other (note 9)	**199**	166	191
Future income taxes (note 5)	**132**	119	—
Total assets	**8 094**	6 833	5 176
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Short-term borrowings	**31**	64	32
Accounts payable and accrued liabilities (notes 12 and 13)	**672**	709	616
Income taxes payable	—	15	15
Future income taxes (note 5)	**28**	9	—
Taxes other than income taxes	**42**	39	46
Current portion of long-term borrowings (note 10)	—	1	1
Total current liabilities	**773**	837	710
Long-term borrowings (notes 10 and 11)	**3 113**	2 192	1 306
Accrued liabilities and other (notes 12 and 13)	**251**	252	236
Future income taxes (note 5)	**1 180**	1 080	816
Commitments and contingencies (note 14)			
Shareholders' equity			
Preferred securities (note 15)	**514**	514	514
Share capital (note 16)	**555**	537	524
Retained earnings	**1 708**	1 421	1 070
Total shareholders' equity	**2 777**	2 472	2 108
Total liabilities and shareholders' equity	**8 094**	6 833	5 176

See accompanying Summary of Significant Accounting Policies and notes.

Approved on behalf of the Board of Directors:

Rick George
Rick George
Director

Robert Korthals
Robert Korthals
Director

consolidated statements of cash flows

for the years ended December 31

($ millions)	2001	2000	1999
OPERATING ACTIVITIES			
Cash flow provided from operations (1), (2)	**831**	958	591
Decrease (increase) in operating working capital			
Accounts receivable (note 4)	**101**	(130)	(101)
Inventories	**(66)**	(31)	14
Accounts payable and accrued liabilities	**(37)**	93	322
Taxes payable	**(17)**	18	12
Cash provided from operating activities	**812**	908	838
CASH USED IN INVESTING ACTIVITIES (2)	**(1 680)**	(1 607)	(1 290)
NET CASH DEFICIENCY BEFORE FINANCING ACTIVITIES	**(868)**	(699)	(452)
FINANCING ACTIVITIES			
Increase (decrease) in short-term borrowings	**(33)**	32	16
Proceeds from issuance of long-term borrowings (note 10)	**500**	—	—
Issuance of preferred securities (note 15)	**—**	—	507
Stuart Oil Shale Project borrowings	**—**	—	11
Repayment of commercial paper borrowings (note 15)	**—**	—	(507)
Net increase in other long-term borrowings	**486**	792	510
Issuance of common shares under stock option plan (note 16)	**15**	9	6
Dividends paid on preferred securities (3) (note 15)	**(48)**	(47)	(37)
Dividends paid on common shares	**(72)**	(71)	(75)
Cash provided from financing activities	**848**	715	431
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**(20)**	16	(21)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	**21**	5	26
CASH AND CASH EQUIVALENTS AT END OF YEAR	**1**	21	5
PER COMMON SHARE (dollars) (note 16)			
(1) Cash flow provided from operations	**3.73**	4.32	2.68
(3) Dividends paid on preferred securities (pre-tax)	**0.21**	0.21	0.17
Cash flow provided from operations after deducting dividends paid on preferred securities	**3.52**	4.11	2.51
(2) See Schedules of Segmented Data on pages 54 and 55			

See accompanying Summary of Significant Accounting Policies and notes.

consolidated statements of changes in shareholders' equity

($ millions)	Preferred Securities	Share Capital	Retained Earnings
At December 31, 1998	—	518	981
Net earnings	—	—	186
Dividends paid on preferred securities	—	—	(22)
Dividends paid on common shares	—	—	(75)
Issuance of preferred securities (note 15)	514	—	—
Issued for cash under stock option plan	—	6	—
At December 31, 1999	514	524	1 070
Net earnings	—	—	377
Dividends paid on preferred securities	—	—	(26)
Dividends paid on common shares	—	—	(71)
Issued for cash under stock option plan	—	9	—
Issued under dividend reinvestment plan	—	4	(4)
Income taxes – impact of new standard	—	—	75
At December 31, 2000	514	537	1 421
Net earnings	—	—	388
Dividends paid on preferred securities	—	—	(26)
Dividends paid on common shares	—	—	(72)
Issued for cash under stock option plan	—	15	—
Issued under dividend reinvestment plan	—	3	(3)
At December 31, 2001	514	555	1 708

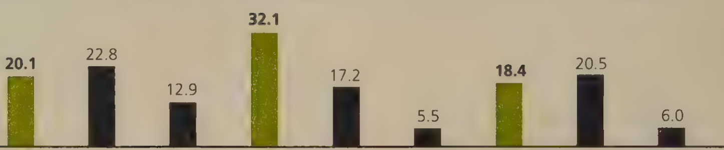
See accompanying Summary of Significant Accounting Policies and notes.

schedules of segmented data*

for the years ended December 31

($ millions)	Oil Sands 2001	Oil Sands 2000	Oil Sands 1999	Natural Gas 2001	Natural Gas 2000	Natural Gas 1999	Sunoco 2001	Sunoco 2000	Sunoco 1999
EARNINGS									
Revenues**									
Sales and other operating revenues	**1 227**	544	461	**178**	237	143	**2 585**	2 604	1 779
Intersegment revenues (note 18) ***	**158**	792	428	**271**	191	163	**3**	—	—
Interest	—	—	—	—	—	—	—	—	—
	1 385	1 336	889	**449**	428	306	**2 588**	2 604	1 779
Expenses									
Purchases of crude oil and products (note 18)	**99**	3	6	—	—	—	**1 721**	1 783	1 090
Operating, selling and general	**481**	467	369	**64**	74	88	**350**	310	270
Exploration	—	—	—	**22**	53	40	—	—	—
Royalties	**30**	98	51	**104**	101	48	—	—	—
Taxes other than income taxes	**12**	12	9	**3**	3	5	**351**	345	320
Depreciation, depletion and amortization	**233**	232	177	**70**	78	87	**56**	54	53
(Gain) loss on disposal of assets	**1**	—	2	**(8)**	(147)	(36)	—	(1)	—
Start-up expenses – Project Millennium	**141**	15	—	—	—	—	—	—	—
Write-off of oil shale assets	—	—	—	—	—	—	—	—	—
Restructuring	—	—	—	**(2)**	65	—	—	—	—
Interest	—	—	—	—	—	—	—	—	—
	997	827	614	**253**	227	232	**2 478**	2 491	1 733
Earnings (loss) before income taxes	**388**	509	275	**196**	201	74	**110**	113	46
Provision for income taxes	**(105)**	(194)	(108)	**(79)**	(103)	(33)	**(30)**	(32)	(19)
Net earnings (loss)	**283**	315	167	**117**	98	41	**80**	81	27
As at December 31									
TOTAL ASSETS	**6 409**	5 079	3 178	**722**	762	962	**934**	911	849
CAPITAL EMPLOYED****	**1 398**	1 412	1 352	**317**	412	727	**483**	386	405
RETURN ON AVERAGE CAPITAL EMPLOYED (%)*****	**6.4**	10.6	9.2	**32.1**	17.2	5.5	**18.4**	20.5	6.0

RETURN ON AVERAGE CAPITAL EMPLOYED (%)****



* The company currently has no foreign geographic segments. See note 4 for information on export sales. Accounting policies for segments are the same as those described in the Summary of Significant Accounting Policies.

** One customer, in the Oil Sands segment, in 2001 represented 10% or more ($450 million) of the company's 2001 consolidated revenues. (2000 – two customers represented 10% or more ($493 million and $355 million); 1999 – one customer represented 10% or more ($281 million)).

*** Intersegment revenues are recorded at prevailing fair market prices and accounted for as if the sales were to third parties.

**** Capital Employed – the total of shareholders' equity and debt (short-term borrowings and current and long-term portions of long-term borrowings), less capitalized costs related to major projects in progress.

***** If capital employed were to include capitalized costs related to major projects in progress, the return on average capital employed would be as stated on this line.

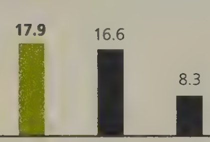
See accompanying Summary of Significant Accounting Policies and notes.

schedules of segmented data* (continued)

for the years ended December 31

($ millions)	Corporate and Eliminations 2001	2000	1999	Total 2001	2000	1999
EARNINGS						
Revenues**						
Sales and other operating revenues	**—**	—	—	**3 990**	3 385	2 383
Intersegment revenues (note 18) ***	**(432)**	(983)	(591)	**—**	—	—
Interest	**5**	3	4	**5**	3	4
	(427)	(980)	(587)	**3 995**	3 388	2 387
Expenses						
Purchases of crude oil and products (note 18)	**(429)**	(979)	(577)	**1 391**	807	519
Operating, selling and general	**115**	67	47	**1 010**	918	774
Exploration	**—**	—	—	**22**	53	40
Royalties	**—**	—	—	**134**	199	99
Taxes other than income taxes	**1**	1	—	**367**	361	334
Depreciation, depletion and amortization	**1**	1	1	**360**	365	318
(Gain) loss on disposal of assets	**—**	—	—	**(7)**	(148)	(34)
Start-up expenses – Project Millennium	**—**	—	—	**141**	15	—
Write-off of oil shale assets	**48**	125	—	**48**	125	—
Restructuring	**—**	—	—	**(2)**	65	—
Interest	**18**	8	26	**18**	8	26
	(246)	(777)	(503)	**3 482**	2 768	2 076
Earnings (loss) before income taxes	**(181)**	(203)	(84)	**513**	620	311
Provision for income taxes	**89**	86	35	**(125)**	(243)	(125)
Net earnings (loss)	**(92)**	(117)	(49)	**388**	377	186
As at December 31						
TOTAL ASSETS	**29**	81	187	**8 094**	6 833	5 176
CAPITAL EMPLOYED******	**32**	22	(121)	**2 230**	2 232	2 363

RETURN ON AVERAGE CAPITAL EMPLOYED (%)****



RETURN ON AVERAGE CAPITAL EMPLOYED (%)********	**7.5**	9.3	6.4

schedules of segmented data* (continued)

for the years ended December 31

($ millions)	Oil Sands 2001	Oil Sands 2000	Oil Sands 1999	Natural Gas 2001	Natural Gas 2000	Natural Gas 1999	Sunoco 2001	Sunoco 2000	Sunoco 1999
CASH FLOW BEFORE FINANCING ACTIVITIES									
Cash provided from (used in) operating activities:									
Cash flow provided from (used in) operations									
Net earnings (loss)	**283**	315	167	**117**	98	41	**80**	81	27
Exploration expenses									
Cash	**—**	—	—	**12**	12	12	**—**	—	—
Dry hole costs	**—**	—	—	**10**	41	28	**—**	—	—
Non-cash items included in earnings									
Depreciation, depletion and amortization	**233**	232	177	**70**	78	87	**56**	54	53
Future income taxes	**89**	189	102	**76**	101	31	**18**	(16)	(33)
Current income tax provision allocated to Corporate	**16**	5	6	**3**	2	2	**12**	48	52
(Gain) loss on disposal of assets	**1**	—	2	**(8)**	(147)	(36)	**—**	(1)	—
Write-off of oil shale assets	**—**	—	—	**—**	—	—	**—**	—	—
Restructuring	**—**	—	—	**(3)**	56	—	**—**	—	—
Other	**(4)**	(12)	—	**3**	(4)	6	**2**	6	3
Overburden removal outlays	**(31)**	(48)	(53)	**—**	—	—	**—**	—	—
Overburden removal outlays – Project Millennium	**(88)**	(27)	—	**—**	—	—	**—**	—	—
Increase (decrease) in deferred credits and other	**(13)**	1	4	**—**	1	1	**(3)**	2	1
Total cash flow provided from (used in) operations	**486**	655	405	**280**	238	172	**165**	174	103
Decrease (increase) in operating working capital	**(35)**	(169)	83	**44**	27	27	**17**	40	69
Total cash provided from (used in) operating activities	**451**	486	488	**324**	265	199	**182**	214	172
Cash provided from (used in) investing activities:									
Capital and exploration expenditures	**(1 479)**	(1 808)	(1 057)	**(132)**	(127)	(200)	**(54)**	(45)	(42)
Deferred maintenance shutdown expenditures	**(5)**	(3)	(22)	**(2)**	(1)	—	**(9)**	(9)	—
Deferred outlays and other investments	**(2)**	(5)	(7)	**(1)**	—	—	**(9)**	(7)	(2)
Proceeds from disposals	**10**	101	1	**22**	314	90	**1**	2	1
Total cash provided from (used in) investing activities	**(1 476)**	(1 715)	(1 085)	**(113)**	186	(110)	**(71)**	(59)	(43)
Net cash surplus (deficiency) before financing activities	**(1 025)**	(1 229)	(597)	**211**	451	89	**111**	155	129

* The company currently has no foreign geographic segments. See note 4 for information on export sales. Accounting policies for segments are the same as those described in the Summary of Significant Accounting Policies.

See accompanying Summary of Significant Accounting Policies and notes.

schedules of segmented data* (continued)

for the years ended December 31

($ millions)	Corporate and Eliminations 2001	2000	1999	Total 2001	2000	1999
CASH FLOW BEFORE FINANCING ACTIVITIES						
Cash provided from (used in) operating activities:						
Cash flow provided from (used in) operations						
Net earnings (loss)	**(92)**	(117)	(49)	**388**	377	186
Exploration expenses						
Cash	**—**	—	—	**12**	12	12
Dry hole costs	**—**	—	—	**10**	41	28
Non-cash items included in earnings						
Depreciation, depletion and amortization	**1**	1	1	**360**	365	318
Future income taxes	**(62)**	(76)	(4)	**121**	198	96
Current income tax provision allocated to Corporate	**(31)**	(55)	(60)	**—**	—	—
(Gain) loss on disposal of assets	**—**	—	—	**(7)**	(148)	(34)
Write-off of oil shale assets	**48**	125	—	**48**	125	—
Restructuring	**—**	—	—	**(3)**	56	—
Other	**7**	(7)	4	**8**	(17)	13
Overburden removal outlays	**—**	—	—	**(31)**	(48)	(53)
Overburden removal outlays – Project Millennium	**—**	—	—	**(88)**	(27)	—
Increase (decrease) in deferred credits and other	**29**	20	19	**13**	24	25
Total cash flow provided from (used in) operations	**(100)**	(109)	(89)	**831**	958	591
Decrease (increase) in operating working capital	**(45)**	52	68	**(19)**	(50)	247
Total cash provided from (used in) operating activities	**(145)**	(57)	(21)	**812**	908	838
Cash provided from (used in) investing activities:						
Capital and exploration expenditures	**(13)**	(18)	(51)	**(1 678)**	(1 998)	(1 350)
Deferred maintenance shutdown expenditures	**—**	—	—	**(16)**	(13)	(22)
Deferred outlays and other investments	**(7)**	(1)	(1)	**(19)**	(13)	(10)
Proceeds from disposals	**—**	—	—	**33**	417	92
Total cash provided from (used in) investing activities	**(20)**	(19)	(52)	**(1 680)**	(1 607)	(1 290)
Net cash surplus (deficiency) before financing activities	**(165)**	(76)	(73)	**(868)**	(699)	(452)

1. oil shale project

Effective April 5, 2001, the company sold its interest in the Stuart Oil Shale Project to joint venture co-owners Southern Pacific Petroleum NL and Central Pacific Minerals NL (SPP/CPM). Under the terms of the sale, the company retains a 5% royalty interest in Stage 1 of the project and SPP/CPM and the company retain worldwide rights to the Alberta Taciuk Processor technology. The company made total payments as part of the transaction in the amount of $5 million (AUD$7 million), which SPP/CPM will use to fund Stage 1 operating, capital and transition costs. The company received 2.5 million SPP shares and 0.926 million CPM shares in consideration. SPP/CPM issued the company 12.5 million SPP share options and 4.6 million CPM share options, exercisable over five years at a strike price of AUD$1.25 per SPP share and AUD$3.38 per CPM share. The company surrendered its partly paid Restricted Class shares (SPP 57 million and CPM 18.85 million) that were acquired in 1997.

In the second quarter of 2001, as a result of the sale of this interest, the company wrote off the carrying value of the property, plant and equipment and the partly paid shares, and extinguished the long-term borrowings and accrued interest. The earnings impact of the sale of Suncor's remaining interest in the project was $48 million pre-tax, $3 million after-tax.

At December 31, 2001, the company holds 2.5 million SPP shares and 0.926 million CPM shares, and 12.5 million SPP share options and 4.6 million CPM share options. The SPP and CPM shares have declined in value and have been written down from $5 million to $2 million. The impact of the write-down was to decrease net earnings by $2 million.

2. restructuring charge

In 2000, the carrying values of certain assets of the company's Natural Gas business were written down to their net estimated recoverable amount and a provision for estimated restructuring costs was recorded.

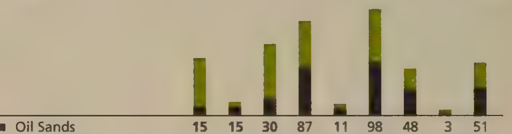
In the third quarter of 2001, some of these properties that were previously written down were sold and provisions for estimated restructuring costs were revised to reflect increased employee termination costs as follows:

($ millions)	**2001**	2000
Non-cash charges:		
Impairment of non-core proved properties	**—**	21
Impairment of non-core unproved properties	**(3)**	18
Write-down of capitalized development costs on proved properties	**—**	17
Cash charges:		
Employee terminations	**1**	6
Consultants and other	**—**	3
	(2)	65

The impact of these adjustments is to increase net earnings by $1 million (2000 – decreased net earnings by $30 million).

3. royalties

Oil Sands Crown royalty payments in 2001 were based on a minimum royalty rate of 1% of gross revenues (2000 and 1999 – 5% of gross revenues).



($ millions)	2001 Crown	2001 Other	2001 Total	2000 Crown	2000 Other	2000 Total	1999 Crown	1999 Other	1999 Total
■ Oil Sands	**15**	**15**	**30**	87	11	98	48	3	51
■ Natural Gas	**93**	**11**	**104**	90	11	101	40	8	48
Total	**108**	**26**	**134**	177	22	199	88	11	99

4. supplemental information

($ millions)	2001	2000	1999
Export sales (1)	**590**	478	233
Exploration expenses			
Geological and geophysical	**11**	10	10
Other	**1**	2	2
Cash costs	**12**	12	12
Dry hole costs	**10**	41	28
Cash and dry hole costs (2)	**22**	53	40
Leasehold impairment (3)	**9**	10	12
	31	63	52
Taxes other than income taxes			
Excise taxes (4)	**343**	336	311
Production, property and other taxes	**24**	25	23
	367	361	334
Interest expense			
Long-term interest cost	**143**	112	71
Less interest capitalized	**(125)**	(104)	(45)
	18	8	26
Cash interest payments	**130**	104	63
Allowance for doubtful accounts	**3**	3	3

In 2001, the company had in place a securitization program to sell, on a revolving, fully serviced and limited recourse basis, up to $170 million of accounts receivable having a maturity of 45 days or less to a third party. As at December 31, 2001, $166 million in accounts receivable had been sold under the program. Under the recourse provisions, the company would provide indemnification against credit losses to a maximum of $54 million. The company believes it has no significant exposure to credit losses. Proceeds received from new securitizations and proceeds from collections reinvested in previous securitizations for the year-ended December 31, 2001 were approximately $44 and $1,804 million, respectively. The company recorded a loss of approximately $3 million on the securitization program in 2001.

(1) Sales of crude oil, natural gas and refined products to customers in the United States and petrochemicals in Europe.

(2) Exploration expenses in the Consolidated Statements of Earnings.

(3) Included in depreciation, depletion and amortization in the Consolidated Statements of Earnings.

(4) Excise taxes are also included in sales and other operating revenues in the Consolidated Statements of Earnings.

5. income taxes

*The assets and liabilities shown on Suncor's balance sheets are calculated using accounting rules known as generally accepted accounting principles. Suncor's income taxes are calculated according to government tax laws and regulations, which could result in different values for some assets and liabilities for income tax purposes. These differences are known as **temporary differences,** because eventually these differences will reverse.*

*The amounts shown on the balance sheets as **future income taxes** represent income taxes that will eventually be payable or recoverable in future years when these temporary differences do reverse.*

See below for more technical details and numbers.

The provision for income taxes reflects an effective tax rate that differs from the statutory tax rate. A reconciliation of the two rates and the dollar effect is as follows:

	2001		2000		1999	
($ millions)	Amount	%	Amount	%	Amount	%
Federal tax rate	**195**	**38**	236	38	118	38
Provincial abatement	**(51)**	**(10)**	(62)	(10)	(31)	(10)
Federal surtax	**6**	**1**	7	1	3	1
Provincial tax rates	**69**	**14**	96	16	48	16
Statutory tax and rate	**219**	**43**	277	45	138	45
Add (deduct) the tax effect of:						
Crown royalties (see note 3)	**48**	**9**	83	13	44	13
Resource allowance	**(77)**	**(15)**	(101)	(17)	(56)	(17)
Large corporations tax	**16**	**3**	10	2	10	3
Tax rate changes on future income taxes*	**(52)**	**(11)**	(13)	(2)	—	—
Attributed Canadian royalty income	**(6)**	**(1)**	(13)	(2)	—	—
Assessments and adjustments	**(11)**	**(2)**	(3)	—	—	—
Other	**(12)**	**(2)**	3	—	(11)	(4)
Income taxes and effective rate	**125**	**24**	243	39	125	40

* Includes $(43) million, (9)% related to revaluation of future income tax balances (2000 – $(13) million, (2)%; 1999 – nil).
2001 income tax payments totalled $23 million (2000 – $22 million; 1999 – $5 million).

At December 31, future income taxes are comprised of the following:

($ millions)	2001 Current	2001 Non-current	2000 Current	2000 Non-current
Future income tax assets:				
Employee future benefits	**4**	**30**	2	39
Reclamation and environmental remediation costs	**8**	**19**	9	23
Royalties	**—**	**44**	—	43
Employee incentive plans	**—**	**29**	—	10
Inventories	**11**	**—**	20	—
Other	**6**	**10**	14	4
	29	**132**	45	119
Future income tax liabilities:				
Depreciation	**—**	**1 105**	—	1 038
Overburden removal costs	**—**	**30**	—	23
Maintenance shutdown costs	**—**	**10**	—	12
Inventories	**10**	**—**	—	—
Other	**18**	**35**	9	7
	28	**1 180**	9	1 080

6. related party transactions

The following table summarizes the company's related party transactions for the year and balances at the end of the year. These transactions are in the normal course of operations and have been carried out on the same terms as would apply with unrelated parties.

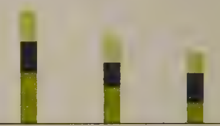
($ millions)	2001	2000	1999
Revenues			
Sales to Sunoco joint ventures:			
Refined products	**602**	600	395
Petrochemicals	**131**	128	108
At the end of the year, amounts due from related parties are as follows:			
Sunoco joint ventures	**33**	58	45

Sales to and balances with Sunoco joint ventures are exchange amounts established and agreed to by the related parties.

The company has exclusive supply agreements with two Sunoco joint ventures for the sale of refined products. The company plans to maintain its relationship with these joint ventures.

The company also has a non-exclusive supply agreement with a Sunoco joint venture for the sale of petrochemicals.

7. inventories



($ millions)	2001	2000	1999
Crude Oil	115	83	47
Refined Products	71	55	67
Materials and Supplies	72	54	47
Total	258	192	161

The replacement cost at December 31, 2001, of all inventories valued at LIFO exceeded their carrying value by $5 million (2000 – $61 million; 1999 – $37 million).

In 2000, the company sold inventories produced in prior years whose LIFO costs were lower than current crude oil and operating costs. The impact of this reduction in inventory was to decrease expenses by $8 million and increase net earnings by $5 million.

8. property, plant and equipment

($ millions)	2001 Cost	2001 Accum. Provision	2000 Cost	2000 Accum. Provision	1999 Cost	1999 Accum. Provision
Oil Sands						
Plant	**1 744**	**557**	1 632	476	1 690	470
Mine and mobile equipment	**1 008**	**337**	918	313	850	243
Pipeline costs	**81**	**23**	81	20	80	17
Capitalized energy services asset lease	**101**	**6**	101	2	—	—
Capitalized aircraft lease	**8**	**—**	8	—	—	—
Project Millennium*	**3 618**	**8**	2 536	6	905	—
Project Firebag – in progress	**275**	**—**	101	—	—	—
	6 835	**931**	5 377	817	3 525	730
Natural Gas						
Proved properties (note 3)	**965**	**423**	877	366	1 190	487
Unproved properties (note 3)	**114**	**48**	125	56	344	171
Pipeline	**20**	**17**	20	17	22	18
Other support facilities and equipment	**14**	**8**	13	6	19	12
	1 113	**496**	1 035	445	1 575	688
Sunoco						
Refinery	**771**	**391**	745	367	740	350
Marketing and transportation	**434**	**209**	405	187	380	165
	1 205	**600**	1 150	554	1 120	515
Corporate						
Stuart Oil Shale Project (note 2)	**—**	**—**	134	—	237	—
Other	**19**	**4**	6	3	7	3
	19	**4**	140	3	244	3
	9 172	**2 031**	7 702	1 819	6 464	1 936
Net property, plant and equipment		**7 141**		5 883		4 528

Interest capitalized during 2001 totalled $125 million (2000 – $104 million; 1999 – $45 million).

Capitalized costs related to the in-progress phase of projects are not being depreciated until the facilities are substantially complete and ready for commercial production to commence. Effective January 1, 2002, Project Millennium commenced commercial production, therefore depreciation will begin in January 2002.

* Project Millennium costs include capitalized interest of $229 million (2000 – $111 million; 1999 – $21 million).
Start-up costs related to Project Millennium have been expensed.

9. deferred charges and other

($ millions)	2001	2000	1999
Oil sands overburden removal costs (see below)	**101**	76	85
Deferred maintenance shutdown costs	**34**	35	45
Investments	**7**	8	8
Goodwill	**14**	14	13
Other	**43**	33	40
	199	166	191
Oil Sands overburden removal costs			
Balance – beginning of year	**76**	85	95
Outlays during year	**119**	75	53
Depreciation on equipment during year	**9**	8	6
	204	168	154
Amortization during year	**(103)**	(92)	(69)
Balance – end of year	**101**	76	85

10. long-term borrowings

($ millions)	2001	2000	1999
Fixed rate borrowings			
Medium-term Notes, maturing in 2011 Interest payable semi-annually*	**500**	—	—
Medium-term Notes, maturing in 2007 Interest payable semi-annually	**400**	400	400
7.4% Debentures, Series C, maturing in 2004 Interest payable semi-annually**	**125**	125	125
Borrowings under or with support of lines of credit converted to fixed rate obligations by interest rate swap transactions, maturing in 2003. Interest payable quarterly at rates averaging 5.6%***	**110**	110	110
Stuart Oil Shale Project borrowings (note 1)	**—**	73	82
Sunoco joint venture borrowings with interest at rates averaging 7.1% at December 31, 2001 (2000 – 7.7%; 1999 – 7.6%)	**6**	4	5
	1 141	712	722
Capital leases****	**109**	109	—
Less current portion of fixed rate long-term borrowings	**—**	1	1
	1 250	820	721
Variable rate borrowings***			
Borrowings with interest at variable rates averaging 2.7% at December 31, 2001 (2000 – 6.0%; 1999 – 5.2%) under or with support of lines of credit	**1 863**	1 372	585
Total long-term borrowings	**3 113**	2 192	1 306

* During 2001, the company issued $500 million of Series 2 Medium-term Notes at an interest rate of 6.7%. The net proceeds received were used to repay commercial paper and bank borrowings.

** During 1996, the company entered into a cross-currency interest rate swap transaction to convert its 7.4% debentures to a 6.2% fixed interest rate U.S. dollar obligation of approximately $91 million. Later in 1996, the company entered into another cross-currency interest rate swap transaction to convert the US$91 million obligation back to a fixed rate Cdn$125 million obligation. The net effect of the two swap transactions was to reduce the effective interest rate on the debentures from 7.3% (7.4% coupon rate) to 5.5%. In 2001, the two swap transactions were terminated, resulting in a deferred gain on settlement of $5 million, which is classified as accrued liabilities in the consolidated balance sheets and which is being recognized in earnings as a reduction of interest expense over the period to maturity of the debentures.

*** During 1998, the company entered into interest rate swap transactions to convert $50 million and $60 million of variable rate borrowings to fixed interest rate obligations at 5.5% and 5.7%, respectively.

**** Obligations under capital leases are as follows:

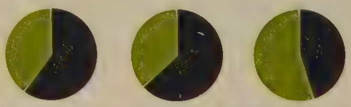
($ millions)	2001	2000
Energy services assets lease with interest at 6.82% maturing in 2004	**101**	101
Aircraft lease with interest at prime plus 0.5% maturing in 2008	**8**	8
	109	109

Future minimum amounts payable under these capital leases are as follows:

	($ millions)
2002	8
2003	8
2004	108
2005	1
2006	—
Later years	6
Total minimum lease payments	131
Less amount representing imputed interest	(22)
Present value of obligation under capital leases	109

***** During 1999, the company entered into a cross-currency interest rate swap transaction to convert US$183 million of variable rate borrowings with interest based on 90-day LIBOR to Cdn$278 million with interest based on 90-day bankers acceptances. In 2001, swap transactions for US$71 million (Cdn$109 million) of these borrowings were settled. There was no gain or loss on settlement.

Long-term Borrowings



(per cent)	2001	2000	1999
Variable rate	60	63	45
Fixed rate	40	37	55

Principal repayments of long-term borrowings other than obligations under capital leases in each of the next five years are as follows:

	($ millions)
2002	—
2003	3
2004	2 099
2005	—
2006	—

11. lines of credit

At December 31, 2001, the company had available $2,337 million in credit and term loan facilities, of which $1,112 million had been drawn, as follows:

- A facility for $600 million that is fully revolving for 364 days, has a term period of three years and expires in 2004.
- A facility for $550 million that is fully revolving for 364 days and expires in 2002.
- A facility for US$112 million (Cdn$169 million) that is non-revolving, has been fully drawn and expires in 2004.
- A facility for $1,003 million that is fully revolving for six years and expires in 2004.
- Uncommitted facilities totalling $15 million, which can be terminated at any time at the option of the lenders.

The company is also authorized, supported by unutilized credit and term loan facilities, to issue commercial paper to a maximum of $900 million, having a term not to exceed 364 days. At December 31, 2001, the company had $861 million in commercial paper outstanding.

These credit facilities are subject to commitment fees, the amounts of which are not significant.

12. accrued liabilities and other

($ millions)	2001	2000	1999
Reclamation and Environmental Remediation Costs (a)	61	70	86
Pension Costs (see note 13)	110	95	96
Other (b)	80	87	54
Total	251	252	236

(a) Reclamation and Environmental Remediation Costs

Total accrued reclamation and environmental remediation costs also include $23 million in current liabilities (2000 – $27 million; 1999 – $13 million). Payments during 2001 totalled $28 million (2000 – $15 million; 1999 – $13 million).

(b) Employee and Director Incentive Plans

Compensation expense recorded under the company's long-term employee incentive plans was $42 million (2000 – $32 million; 1999 – $26 million). Compensation expense is an estimated amount, based on the market price of the company's common shares and expected performance achievement, and is therefore subject to measurement uncertainty and volatility. Vesting of these plans will occur on April 1, 2002. At December 31, 2001, the estimated portion of these awards expected to be paid in cash of $32 million is included in accrued liabilities, with the remaining $72 million included in accrued liabilities and other.

Compensation expense in the form of common share equivalents under the directors' compensation plan is not significant.

13. employee future benefits

When employees work for Suncor, they are eligible to receive pension, health care and insurance benefits when they retire. This ***Benefit Obligation*** *or commitment that Suncor has to employees and retirees at December 31, 2001, was $554 million.*

As required by government regulations and plan performance, Suncor sets aside funds, which are in the custody of an independent trustee, to meet these obligations. At the end of December, 2001, ***Plan Assets*** *to meet the* ***Benefit Obligation*** *were $301 million.*

The excess of the ***Benefit Obligation*** *over* ***Plan Assets*** *of $253 million represents the* ***Net Unfunded Obligation.***

See below for more technical details and numbers.

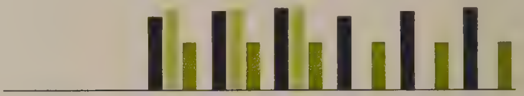
Defined Benefit Pension Plans and Other Post-retirement Benefits

The company's defined benefit pension plans provide a pension benefit at retirement based upon years of service and final average earnings. The defined benefit pension plans consist of a funded plan that covers most employees, and unfunded supplementary benefit plans that provide supplemental retirement benefits to executives. Under the funded plan, the company makes contributions to an independent trustee to cover pension payment obligations to retired employees. The trustee acts as the depository for contributions, the disbursing agent and custodian of the pension plan's assets. These assets are managed by a pension fund investment committee, on behalf of the beneficiaries, which retains independent managers and advisers.

The company's other post-retirement benefits program, which is unfunded, includes certain health care and life insurance benefits provided to retired employees and eligible surviving dependants. Retirees share in the cost of providing these benefits.

Company contributions to the funded pension plan, the present value of pension and other post-retirement benefit obligations and periodic benefit costs are determined by an independent actuary in accordance with regulatory requirements, based on management's best estimate of actuarial assumptions.

Assumptions and Estimates



(per cent)	Pension Benefits			Other Post-retirement Benefits		
	2001	2000	1999	**2001**	2000	1999
■ Discount Rate	**6.50**	7.00	7.25	**6.50**	7.00	7.25
Expected Return on Plan Assets	**7.25**	7.25	7.25	—	—	—
■ Rate of Compensation Increase	**4.25**	4.25	4.25	**4.25**	4.25	4.25

The following table presents information about the funded status of the plans and obligations recognized in the consolidated balance sheets at December 31:

	Pension Benefits			Other Post-retirement Benefits		
	2001	2000	1999	**2001**	2000	1999
Change in benefit obligation						
Benefit obligation at beginning of year	**404**	364	403	**79**	69	72
Service costs	**14**	12	15	**3**	3	4
Interest costs	**28**	26	24	**6**	5	4
Plan participants' contribution	**3**	3	2	**—**	—	—
Amendments	**—**	—	—	**—**	—	(8)
Actuarial (gain) loss	**34**	23	(61)	**7**	4	(1)
Benefits paid	**(22)**	(24)	(19)	**(2)**	(2)	(2)
Benefit obligation at end of year	**461**	404	364	**93**	79	69
Change in plan assets*						
Fair value of plan assets at beginning of year	**322**	316	278	**—**	—	—
Actual return on plan assets	**(14)**	15	39	**—**	—	—
Employer contribution	**12**	12	16	**—**	—	—
Plan participants' contribution	**3**	3	2	**—**	—	—
Benefits paid	**(22)**	(24)	(19)	**—**	—	—
Fair value of plan assets at end of year	**301**	322	316	**—**	—	—
Net unfunded obligation	**(160)**	(82)	(48)	**(93)**	(79)	(69)
Items not yet recognized in earnings:						
Unamortized transitional asset	**—**	(8)	(16)	**—**	—	—
Unamortized net actuarial loss	**109**	45	18	**19**	13	11
Accrued benefit liability	**(51)**	(45)	(46)	**(74)**	(66)	(58)
Current portion	**(15)**	(15)	(8)	**(2)**	(2)	(2)
Long-term portion	**(36)**	(30)	(38)	**(72)**	(64)	(56)
	(51)	(45)	(46)	**(74)**	(66)	(58)

* Assets in the employees' pension plan consist of marketable equity securities, government and corporate bonds and short-term notes. Pension plan assets are not the company's assets and therefore are not included in the consolidated balance sheets.

The above benefit obligation at year-end includes funded and unfunded plans, as follows:

	Pension Benefits			Other Post-retirement Benefits		
	2001	2000	1999	**2001**	2000	1999
Funded plan	**377**	334	309	**—**	—	—
Unfunded plans	**84**	70	55	**93**	79	69
Benefit obligation at end of year	**461**	404	364	**93**	79	69

The components of net periodic benefit cost are as follows:

	Pension Benefits			Other Post-retirement Benefits		
	2001	2000	1999	**2001**	2000	1999
Service costs	**14**	12	15	**3**	3	4
Interest costs	**28**	26	24	**6**	5	4
Expected return on plan assets	**(23)**	(22)	(22)	**—**	—	—
Amortization of transitional asset	**(8)**	(8)	(8)	**—**	—	—
Amortization of net actuarial loss	**9**	6	12	**1**	1	1
Net periodic benefit cost	**20**	14	21	**10**	9	9

The unamortized net actuarial loss represents annually calculated differences between actual and projected plan performance. These amounts are amortized as part of the net periodic benefit cost over the expected average remaining service life of employees of 13 years for pension benefits (2000 and 1999 – 13 years), and over the expected average future service life to full eligibility age of 11 years for post-retirement benefits.

In order to measure the expected cost of other post-retirement benefits, a 9.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2001. The rate was assumed to decrease gradually each year to a rate of 5% for 2010 and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for other post-retirement benefit obligations. A 1% change in assumed health care cost trend rates would have the following effects:

($ millions)	1% Increase	1% Decrease
Effect on total of service and interest cost components of net periodic post-retirement health care benefit cost	2	(1)
Effect on the health care component of the accumulated post-retirement benefit obligation	17	(13)

Defined Contribution Pension Plan

The company has a defined contribution plan, under which both the company and employees make contributions. Company contributions, which totalled $4 million (2000 – $4 million; 1999 – $4 million), are based on employees' earnings and contributions.

14. commitments and contingencies

(a) Operating Commitments

In order to ensure continued availability of, and access to, facilities and services to meet its operational requirements, the company enters into non-cancellable operating leases for service stations, office space and other property and equipment, as well as transportation service agreements for pipeline capacity and an energy services agreement. Under contracts existing at December 31, 2001, future minimum amounts payable under these leases and agreements are as follows:

($ millions)	Pipeline Capacity and Energy Services *	Operating Leases
2002	131	45
2003	134	42
2004	133	36
2005	141	32
2006	148	29
Later years	3 826	89
	4 513	273

* Includes annual tolls payable under a transportation service agreement with a major pipeline company to use a portion of its pipeline capacity and tankage for the shipment of crude oil from Fort McMurray to Hardisty, Alberta. The agreement commenced in 1999 and extends to 2028. As the initial shipper on the pipeline, Suncor's annual tolls payable under the agreement could be subject to annual adjustments.

To meet the energy needs of its oil sands operation, Suncor has a commitment under long-term energy agreements to obtain a portion of the power and all of the steam generated by a cogeneration facility owned by a major energy company. Effective October 1999, this company also commenced managing the operations of Suncor's existing energy services facility.

(b) Contingencies

The company is subject to various regulatory and statutory requirements relating to the protection of the environment. These requirements, in addition to contractual agreements and management decisions, result in the accrual of estimated reclamation and environmental remediation costs. These costs are accrued at the company's natural gas and oil sands operations on the unit of production basis. Estimated environmental remediation costs at service stations are also accrued upon completion of site investigations. These costs are reduced by any estimated gains likely to be realized on a sale of these sites. Any changes in these estimates will affect future earnings.

Under the company's business interruption insurance coverage, the company would bear the first $415 million of any loss arising from a future insured incident at its Oil Sands operations.

The company is defendant and plaintiff in a number of legal actions that arise in the normal course of business.

Costs attributable to these commitments and contingencies are expected to be incurred over an extended period of time and to be funded mainly from the company's cash provided from operating activities. Although the ultimate impact of these matters on net earnings cannot be determined at this time, it could be material for any one quarter or year. The company believes that any liabilities which might arise pertaining to such matters would not be expected to have a material effect on the company's consolidated financial position.

15. preferred securities

During 1999, the company completed a Canadian offering of $276 million of 9.05% preferred securities and a U.S. offering of US$162.5 million of 9.125% preferred securities, the proceeds of which totalled Cdn$507 million after issue costs of $17 million ($10 million after income tax credits of $7 million). The preferred securities are unsecured junior subordinated debentures, due in 2048 and redeemable at the company's option on or after March 15, 2004. Subject to certain conditions, the company has the right to defer payment of interest on the securities for up to 20 consecutive quarterly periods. Deferred interest and principal amounts are payable in cash, or, at the option of the company, from the proceeds on the sale of equity securities of the company delivered to the trustee of the preferred securities. Accordingly, the preferred securities are classified as share capital in the consolidated balance sheet and the interest distributions thereon, net of income taxes, are classified as dividends. Proceeds from the offerings were used to repay commercial paper borrowings.

16. share capital

(a) Authorized:

Common Shares

The company is authorized to issue an unlimited number of common shares without nominal or par value.

Preferred Shares

The company is authorized to issue an unlimited number of preferred shares without nominal or par value in series.

(b) Issued:

The number of common shares and common share options outstanding, common share prices and per share calculations, for both current and prior periods, reflect a two-for-one split of the company's common shares during 2000.

	Common Shares	
($ millions)	Number	Amount
Balance as at December 31, 1998	220 433 656	518
Issued for cash under stock option plan	587 850	6
Issued under dividend reinvestment plan	10 732	—
Balance as at December 31, 1999	221 032 238	524
Issued for cash under stock option plan	738 176	9
Issued under dividend reinvestment plan	130 165	4
Balance as at December 31, 2000	221 900 579	537
Issued for cash under stock option plan	1 048 069	15
Issued under dividend reinvestment plan	29 597	3
Balance as at December 31, 2001	**222 978 245**	**555**

Common Share Options

i) Executive Stock Plan

Under this plan, the company has granted common share options to non-employee directors and certain executives of the company and its subsidiaries. The exercise price of an option is equal to the market value of the common shares at the date of grant. Options granted to non-employee directors are exercisable immediately. Options granted to employees are exercisable as follows: one-third after one year, the second third after two years and the final third after three years from the grant date. No option may be exercisable more than 10 years after the grant date.

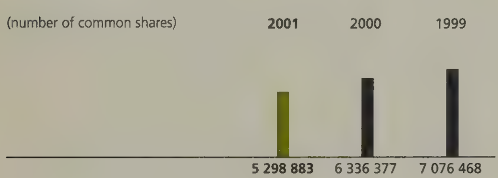
ii) Employee Stock Option Program

Under this program, the company granted 1,063,000 share options to certain senior employees. The exercise price for these grants was equal to or greater than the market value of the common shares at the grant date. Options vest and are exercisable on April 1, 2002, one-half at that time and the other half based on achievement of certain performance measurement criteria.

The following tables cover all common share options granted by the company:

Exercise price per share (dollars)	Number	Range	Weighted Average
Outstanding, December 31, 1998	5 397 238	4.75 – 26.38	16.64
Granted	1 090 456	20.25 – 30.18	20.70
Exercised	(583 040)	4.75 – 24.55	9.76
Cancelled	(46 668)	15.54 – 26.08	25.73
Outstanding, December 31, 1999	5 857 986	4.75 – 30.18	18.01
Granted	950 016	26.08 – 38.55	31.29
Exercised	(737 202)	4.75 – 24.55	12.57
Cancelled	(209 925)	20.25 – 33.03	26.03
Outstanding, December 31, 2000	5 860 875	4.75 – 38.55	20.55
Granted	1 090 360	31.88 – 42.70	35.26
Exercised	(1 014 334)	4.75 – 32.95	14.60
Cancelled	(52 866)	20.25 – 40.40	28.42
Outstanding, December 31, 2001	**5 884 035**	**4.75 – 42.70**	**24.24**
Exercisable, December 31			
1999	2 609 816	4.75 – 26.98	12.89
2000	3 067 594	4.75 – 31.98	15.42
2001	**3 067 806**	**4.75 – 42.70**	**19.34**

Common shares authorized for issuance by the Board of Directors, that remain available for the granting of future options, at December 31:



The following table is an analysis of outstanding and exercisable common share options as at December 31, 2001:

	Outstanding			Exercisable	
Exercise Price	Number	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price Per Share	Number	Weighted Average Exercise Price Per Share
4.75 – 12.80	795 460	3	9.94	795 460	9.94
15.54 – 20.25	1 475 746	6	18.18	1 187 641	17.67
24.55 – 28.12	1 670 761	6	25.56	648 584	24.73
28.40 – 33.73	862 436	8	31.44	335 906	31.49
34.90 – 42.70	1 079 632	9	35.26	100 215	38.03
Total	5 884 035	6	24.24	3 067 806	19.34

iii) Earnings Per Common Share

The following table provides a reconciliation between basic and diluted earnings per share:

($ millions)	**2001**	2000	1999
Net earnings attributable to common shareholders	**362**	351	163
Dividends on preferred securities	**— ****	26 ***	— ****
Net earnings before deducting dividends on preferred securities	**362 ****	377 ***	163 ****
(millions of common shares)			
Weighted-average number of common shares	**222**	221	221
Dilutive securities:			
Options/shares issued under long-term incentive plan	**3**	2	2
Preferred securities converted	**— ****	17 ***	— ****
Weighted-average number of diluted common shares	**225**	240	223
(dollars per common share)			
Basic earnings per share	**1.63 ***	1.58 *	0.74 *
Diluted earnings per share	**1.61 ****	1.57 ***	0.73 ****

* Basic earnings per share is the net earnings attributable to common shareholders divided by the weighted-average number of common shares.

** For the year-ended December 31, 2001, diluted earnings per share is the net earnings attributable to common shareholders divided by the weighted-average number of diluted common shares. Dividends on preferred securities of $26 million and preferred securities converted of 13 million shares have an anti-dilutive impact, therefore they are not included in the calculation of diluted earnings per share.

*** For the year-ended December 31, 2000, diluted earnings per share is the net earnings before deducting dividends on preferred securities divided by the weighted-average number of diluted common shares.

**** For the year-ended December 31, 1999, diluted earnings per share is the net earnings attributable to common shareholders divided by the weighted-average number of diluted common shares. Dividends on preferred securities of $22 million and preferred securities converted of 22 million shares have an anti-dilutive impact, therefore they are not included in the calculation of diluted earnings per share.

iv) Fair Value of Options Granted

The weighted average fair value of common share options granted in 2001 is $6.41 per share (2000 – $7.12 per share; 1999 – $7.01 per share). The fair value of common share options granted is estimated as at the grant date using the Black-Scholes option-pricing model, using the following assumptions:

	2001	2000	1999
Dividend	**$0.34/ share**	$0.34/ share	$0.34/ share
Risk-free interest rate	**5.07%**	6.45%	4.89%
Expected life	**5 years**	7 years	7 years
Expected volatility	**35%**	37%	32%

The company does not recognize compensation cost in the consolidated statement of earnings when common share options are granted to non-employee directors and employees. Had compensation cost been determined on the basis of fair values using the Black-Scholes option-pricing model, 2001 net earnings would have been lower by $9 million (2000 – $7 million; 1999 – $5 million), and 2001 earnings per share would have been lower by $0.04 (2000 – $0.03; 1999 – $0.02).

17. financial instruments

(a) Balance Sheet Financial Instruments

The company's financial instruments recognized in the consolidated balance sheets consist of cash and cash equivalents, accounts receivable, derivative contracts not accounted for as hedges, investments in SPP and CPM, substantially all current liabilities, except for income taxes payable and future income taxes, and long-term borrowings.

The estimated fair values of recognized financial instruments have been determined based on the company's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

The fair values of cash and cash equivalents, accounts receivable and current liabilities approximate their carrying amounts due to the short-term maturity of these instruments.

At December 31, 2001, the company had outstanding crude oil and U.S. dollar swap contracts maturing in 2004, fixing the purchase price of 2 130 000 barrels of crude oil at Cdn$49 million. These derivative contracts, which have not been accounted for as hedges, had a fair value and carrying value of $13 million at December 31, 2001 (2000 – $10 million; 1999 – $(2) million).

The fair value of the company's investment in the shares of SPP and CPM is determined based on quoted market prices.

The following table summarizes estimated fair value information about the company's long-term borrowings at December 31:

($ millions)	2001 Carrying Amount	2001 Fair Value	2000 Carrying Amount	2000 Fair Value	1999 Carrying Amount	1999 Fair Value
Long-term borrowings						
– fixed rate	**1 025**	**1 047**	525	528	525	516
– variable rate	**1 974**	**1 974**	1 482	1 482	695	695
– Sunoco joint ventures	**6**	**6**	3	3	4	4
– Stuart Oil Shale Project	—	—	73	73	82	82
– capital leases	**109**	**109**	109	109	—	—

The fair value of the company's fixed rate long-term borrowings, which are publicly traded, is based on quoted market prices. The fair value of the company's variable rate long-term borrowings, capital leases, and proportionate share of the long-term borrowings of its Sunoco joint ventures approximates the carrying amount.

(b) Unrecognized Derivative Financial Instruments

The company is also a party to certain derivative financial instruments which are not recognized in the consolidated balance sheets, as follows:

Revenue and Margin Hedges

The company enters into crude oil and foreign currency swap and option contracts to protect its future Canadian dollar earnings and cash flows from the potential adverse impact of low petroleum prices and an unfavourable U.S./Canadian dollar exchange rate. These contracts reduce fluctuations in sales revenues by locking in fixed prices, or a range of fixed prices, and exchange rates on the portion of its crude oil sales covered by the contracts. The company also enters into crude oil and heating oil swap contracts to lock in fixed margins on the portion of refined product sales covered by the contracts. While these contracts reduce the risk of exposure to adverse changes in commodity prices and exchange rates, they also reduce the potential benefit of favourable changes in commodity prices and exchange rates.

The contracts do not require the payment of premiums or cash margin deposits prior to settlement. On settlement, these contracts result in cash receipts or payments by the company for the difference between the contract and market rates for the applicable dollars and volumes hedged during the contract term. Such cash receipts or payments offset corresponding decreases or increases in the company's sales revenues or crude oil purchase costs. For accounting purposes, amounts received or paid on settlement are recorded as part of the related hedged sales or purchase transactions.

Contracts outstanding at December 31 were as follows:

($ millions except for average price)	Quantity	Average Price *	Revenue Hedged	Hedge Period
REVENUE HEDGES				
As at December 31, 2001				
Crude oil swaps and options*	**40 576 bbl/day**	**30**	**444**	**2002**
	424 bbl/day	**21 (a)**	**3 (a)**	**2002**
	43 000 bbl/day	**22 – 27 (a)**	**345 – 424 (a)**	**2002**
	44 000 bbl/day	**21 – 26 (a)**	**337 – 418 (a)**	**2003**
	11 000 bbl/day	**21 – 24 (a)**	**84 – 96 (a)**	**2004**
	15 000 bbl/day	**22 (a)**	**120 (a)**	**2005**
As at December 31, 2000				
Crude oil swaps and options*	42 710 bbl/day	28	436	2001
	4 790 bbl/day	20 (a)	35 (a)	2001
	10 000 bbl/day	26 – 32 (a)	95 – 117 (a)	2001
	41 000 bbl/day	28	426	2002
	7 000 bbl/day	22 – 26 (a)	56 – 66 (a)	2002
As at December 31, 1999				
Crude oil swaps*	52 655 bbl/day	26	503	2000
	9 845 bbl/day	19 (a)	67 (a)	2000
	35 000 bbl/day	26	327	2001
	4 000 bbl/day	26	38	2002
U.S. dollar swaps	US$81	1.41	114	2001
	US$289	1.41	408	2002

* Average price for crude oil swaps is WTI per barrel at Cushing, Oklahoma.

(a) Average price and revenue hedged is in U.S. dollars, with no foreign exchange component.

($ millions except for average margin)	Quantity bbl/day	Average Margin US$/bbl	Margin Hedged US$	Hedge Period
MARGIN HEDGES				
Refined product sales and crude purchase swaps				
As at December 31, 2001	—	—	—	—
As at December 31, 2000	6 575	5	12	2001
As at December 31, 1999	—	—	—	—

Interest Rate Hedges

The company enters into interest rate and cross-currency interest rate swap contracts as part of its risk management strategy to minimize exposure to interest rate fluctuations. The interest rate swap contracts involve an exchange of floating rate and fixed rate interest payments between the company and a financial institution. The cross-currency swap contracts involve an exchange of Canadian dollar interest payments and U.S. dollar interest payments between the company and a financial institution, and an exchange of Canadian and U.S. dollar principal amounts at the maturity date of the underlying borrowing to which the swaps relate. The swap transactions are completely independent from and have no direct effect on the relationship between the company and its lenders. The differentials on the exchange of periodic interest payments are recognized in the accounts as an adjustment to interest expense.

The notional amounts of interest rate and cross-currency interest rate swap contracts outstanding at December 31, 2001 are detailed in note 10, Long-Term Borrowings.

Fair Value of Derivative Financial Instruments

The fair value of these hedging derivative financial instruments is the estimated amount, based on brokers' quotes, that the company would receive (pay) to terminate the contracts. Such amounts, which also represent the unrecognized and unrecorded gain (loss) on the contracts, were as follows at December 31:

($ million)	**2001**	2000	1999
Revenue hedge swaps and options	**54**	(247)	(136)
Margin hedge swaps	**(2)**	(11)	—
U.S. dollar swaps	**—**	—	(1)
Interest rate and cross-currency interest rate swaps	**4**	5	—
	56	(253)	(137)

Counterparty Credit Risk

The company may be exposed to certain losses in the event that counterparties to the derivative financial instruments are unable to meet the terms of the contracts. The company's exposure is generally limited to those counterparties holding derivative contracts with positive fair values at the reporting date. The company minimizes this risk by entering into agreements only with highly rated financial institutions, and through regular management review of potential exposure to, and credit ratings of, such financial institutions. At December 31, the company had exposure to credit risk with counterparties as follows:

($ millions)	**2001**	2000
Derivative contracts not accounted for as hedges	**12**	8
Unrecognized derivative contracts	**93**	—
	105	8

18. accounting for intersegment revenues

During the first quarter of 2001, the company changed the methodology of accounting for sales from its upstream operations to its downstream operations from a deeming concept to one based on actual product shipments. Under the deeming concept, upstream sales, except for sales to third parties under long-term contracts, were deemed to be sold to downstream operations and, therefore, eliminated on consolidation whether or not product was actually shipped. The company's current operational activities are such that product shipped from its upstream operations to its downstream operations is considerably less than previous years and therefore, this change better reflects the company's current operational activities and enhances comparability within the industry.

The impact of this change in methodology in accounting for intersegment sales, which has been applied prospectively, is to increase both sales and other operating revenues and purchases of crude oil and products by $473 million. There is no impact on consolidated and segmented net earnings.

quarterly summary

(unaudited)

Financial Data

($ millions except per share amounts)	For the Quarter Ended Mar 31 2001	June 30 2001	Sept 30 2001	Dec 31 2001	Total Year 2001	For the Quarter Ended Mar 31 2000	June 30 2000	Sept 30 2000	Dec 31 2000	Total Year 2000	For the Quarter Ended Mar 31 1999	June 30 1999	Sept 30 1999	Dec 31 1999	Total Year 1999
Revenues	**1 001**	**1 098**	**1 013**	**883**	**3 995**	779	820	862	927	3 388	469	564	639	715	2 387
Net earnings (loss)															
Oil Sands	**69**	**108**	**69**	**37**	**283**	90	81	76	68	315	17	34	43	73	167
Natural Gas	**53**	**39**	**13**	**12**	**117**	8	16	43	31	98	3	13	20	5	41
Sunoco	**23**	**45**	**12**	**—**	**80**	19	20	19	23	81	5	3	12	7	27
Corporate and eliminations	**(20)**	**(28)**	**(21)**	**(23)**	**(92)**	(12)	(6)	(88)	(11)	(117)	(14)	(17)	(5)	(13)	(49)
	125	**164**	**73**	**26**	**388**	105	111	50	111	377	11	33	70	72	186
Per common share															
– net earnings attributable to common shareholders															
– basic	**0.53**	**0.71**	**0.30**	**0.09**	**1.63**	0.45	0.47	0.19	0.47	1.58	0.04	0.12	0.29	0.29	0.74
– diluted	**0.52**	**0.70**	**0.30**	**0.09**	**1.61**	0.44	0.46	0.20	0.47	1.57	0.04	0.12	0.29	0.28	0.73
– cash dividends	**0.085**	**0.085**	**0.085**	**0.085**	**0.34**	0.085	0.085	0.085	0.085	0.34	0.085	0.085	0.085	0.085	0.34
Cash flow provided from (used in) operations															
Oil Sands	**140**	**117**	**139**	**90**	**486**	199	181	156	119	655	53	90	104	158	405
Natural Gas	**127**	**76**	**42**	**35**	**280**	48	42	64	84	238	42	43	39	48	172
Sunoco	**50**	**67**	**30**	**18**	**165**	46	38	49	41	174	23	17	37	26	103
Corporate and eliminations	**(42)**	**(14)**	**(34)**	**(10)**	**(100)**	(24)	(17)	(40)	(28)	(109)	(25)	(21)	(33)	(10)	(89)
	275	**246**	**177**	**133**	**831**	269	244	229	216	958	93	129	147	222	591

Operating Data

($ millions except per share amounts)	For the Quarter Ended Mar 31 2001	June 30 2001	Sept 30 2001	Dec 31 2001	Total Year 2001	For the Quarter Ended Mar 31 2000	June 30 2000	Sept 30 2000	Dec 31 2000	Total Year 2000	For the Quarter Ended Mar 31 1999	June 30 1999	Sept 30 1999	Dec 31 1999	Total Year 1999
OIL SANDS															
Production (a)	**113.4**	**109.7**	**116.5**	**153.0**	**123.2**	114.8	116.7	114.2	110.0	113.9	95.5	112.0	101.5	113.2	105.6
Sales (a)															
– light sweet crude oil	**53.0**	**55.0**	**54.2**	**62.4**	**56.2**	67.7	64.3	61.4	64.0	64.3	54.6	41.3	52.1	62.8	52.7
– diesel	**13,5**	**15.2**	**15.0**	**15.3**	**14.8**	8.7	8.6	8.9	11.0	9.3	7.9	6.8	8.4	9.5	8.2
– light sour crude oil	**31.4**	**31.5**	**40.6**	**64.3**	**42.0**	39.1	41.7	35.6	27.5	35.8	27.3	47.9	40.6	35.1	37.5
– bitumen	**8.6**	**13.0**	**8.0**	**4.3**	**8.5**	2.4	3.5	7.0	11.0	6.2	1.5	6.9	6.9	—	3.8
	106.5	**114.7**	**117.8**	**146.3**	**121.5**	117.9	118.1	112.9	113.5	115.6	91.3	102.9	108.0	107.4	102.2
Average sales price (b)															
– light sweet crude oil	**36.09**	**36.05**	**35.20**	**30.22**	**34.17**	34.35	33.54	36.21	37.22	35.31	20.55	24.47	27.23	30.81	26.06
– other (diesel, light sour crude oil and bitumen)	**25.66**	**27.12**	**28.21**	**20.12**	**24.86**	28.46	28.22	27.84	23.71	27.09	19.18	19.60	21.45	25.91	21.48
– total	**30.84**	**31.40**	**31.43**	**24.43**	**29.17**	31.84	31.12	32.39	31.33	31.67	20.00	21.57	24.24	28.77	23.84
– total*	**38.17**	**38.35**	**37.37**	**25.65**	**34.21**	39.19	39.40	43.41	43.27	41.29	18.52	22.29	27.56	33.72	25.89
Cash operating costs (1) (c)	**15.40**	**17.00**	**18.25**	**17.45**	**17.00**	11.10	12.20	14.50	16.40	13.55	12.55	10.90	12.35	11.15	11.70
Total operating costs (2) (c)	**18.60**	**19.65**	**20.95**	**19.40**	**19.60**	15.50	16.60	18.55	19.50	17.25	15.60	14.30	15.30	15.10	15.05

Operating Data (continued)

($ millions except per share amounts)	For the Quarter Ended Mar 31 2001	June 30 2001	Sept 30 2001	Dec 31 2001	Total Year 2001	For the Quarter Ended Mar 31 2000	June 30 2000	Sept 30 2000	Dec 31 2000	Total Year 2000	For the Quarter Ended Mar 31 1999	June 30 1999	Sept 30 1999	Dec 31 1999	Total Year 1999
NATURAL GAS															
Gross production**															
Conventional															
– natural gas (d)	**177**	**177**	**176**	**180**	**177**	222	195	200	183	200	229	225	231	219	226
– natural gas liquids (a)	**2.3**	**2.3**	**2.4**	**2.4**	**2.4**	3.5	3.1	2.8	2.5	3.0	4.7	4.1	4.1	4.0	4.2
– crude oil (a)***	**1.7**	**1.5**	**1.5**	**1.3**	**1.5**	8.1	3.5	3.6	1.6	4.2	10.8	9.7	8.4	7.9	9.2
– total (e)	**33.5**	**33.3**	**33.2**	**33.7**	**33.4**	48.6	39.1	39.7	34.6	40.5	53.7	51.3	51.0	48.4	51.1
Average sales price															
– natural gas (f)	**10.73**	**6.78**	**3.90**	**3.10**	**6.09**	2.96	3.70	4.63	8.02	4.72	2.18	2.15	2.48	2.96	2.44
– natural gas (f)*	**10.81**	**6.82**	**3.90**	**3.09**	**6.12**	2.97	3.70	4.62	8.05	4.73	2.10	2.17	2.58	3.11	2.48
– natural gas liquids (b)	**45.07**	**39.62**	**30.26**	**23.47**	**34.38**	33.16	32.80	39.56	43.00	36.66	11.88	16.70	22.81	27.12	19.32
– crude oil – conventional (b)	**37.35**	**36.75**	**33.17**	**27.17**	**33.92**	26.30	30.04	33.09	36.01	29.50	18.48	20.48	20.55	25.21	20.94
– crude oil – conventional (b)*	**42.12**	**42.30**	**37.86**	**28.60**	**38.14**	38.23	38.65	42.31	44.35	39.80	16.28	21.89	28.01	32.72	24.01
SUNOCO															
Refined product sales (g)****	**14.9**	**15.3**	**15.1**	**14.0**	**14.8**	14.3	15.1	14.0	15.2	14.6	13.1	14.1	13.9	14.2	13.8
Natural gas sales (d)	**92**	**102**	**95**	**92**	**95**	84	78	74	95	83	93	86	87	90	89
Margins – refining (3) (h)	**6.2**	**8.1**	**4.3**	**3.7**	**5.7**	5.4	6.3	6.1	5.8	5.9	3.4	3.3	4.8	4.3	4.0
– retail (4) (h)	**6.1**	**7.6**	**5.9**	**6.9**	**6.6**	6.8	6.4	6.4	7.0	6.6	7.9	7.6	6.9	7.2	7.4
Utilization of refining capacity (%)	**88**	**98**	**99**	**83**	**92**	102	99	96	95	98	97	93	100	92	95

* Excludes the impact of hedging activities.

** Currently all Natural Gas production is located in the Western Canada Sedimentary Basin.

*** Before deducting 2001 Alberta Crown royalty of 0.2 thousand barrels per day (2000 – 0.5 thousand barrels per day; 1999 – 0.9 thousand barrels per day).

**** Excludes sales through joint venture interests.

Definitions

(1) Cash operating costs – operating, selling and general expenses, taxes other than income taxes, and overburden cash expenditures for the period.

(2) Total operating costs – cash and non-cash operating costs (total Oil Sands expenses less purchases of crude oil and products and royalties in Schedules of Segmented Data on page 52 and 53).

(3) Refining margin – average wholesale unit price from all products minus average unit cost of crude oil.

(4) Retail margin – average street price of Sunoco-branded retail gasoline minus refining gasoline price.

(a) thousands of barrels per day
(b) dollars per barrel
(c) dollars per barrel sold rounded to the nearest $0.05
(d) millions of cubic feet per day
(e) BOE (6:1 basis) per day
(f) dollars per thousand cubic feet
(g) thousands of cubic metres per day
(h) cents per litre

Metric conversion
Crude oil, refined products, etc. 1m³ (cubic metre) = approx. 6.29 barrels
Natural gas 1m³ (cubic metre) = approx. 35.49 cubic feet

five-year financial summary

(unaudited)

($ millions except for ratios)	**2001**	2000	1999	1998	1997
Revenues					
Oil Sands	**1 385**	1 336	889	768	751
Natural Gas	**449**	428	306	290	302
Sunoco	**2 588**	2 604	1 779	1 533	1 673
Corporate and eliminations	**(427)**	(980)	(587)	(521)	(572)
	3 995	3 388	2 387	2 070	2 154
Net earnings (loss)					
Oil Sands	**283**	315	167	145	175
Natural Gas	**117**	98	41	24	23
Sunoco	**80**	81	27	37	36
Corporate and eliminations	**(92)**	(117)	(49)	(28)	(20)
	388	377	186	178	214
Cash flow provided from (used in) operations					
Oil Sands	**486**	655	405	320	331
Natural Gas	**280**	238	172	167	162
Sunoco	**165**	174	103	112	121
Corporate and eliminations	**(100)**	(109)	(89)	(19)	(39)
	831	958	591	580	575
Capital and exploration expenditures					
Oil Sands	**1 479**	1 808	1 057	507	491
Natural Gas	**132**	127	200	242	240
Sunoco	**54**	45	42	60	54
Corporate	**13**	18	51	127	62
	1 678	1 998	1 350	936	847
Total assets	**8 094**	6 833	5 176	4 104	3 457
Capital employed*					
Debt					
Short-term borrowings	**31**	64	32	16	36
Current portion of long-term borrowings	**—**	1	1	1	6
Long-term borrowings	**3 113**	2 192	1 306	1 298	767
Shareholders' equity	**2 777**	2 472	2 108	1 499	1 391
	5 921	4 729	3 447	2 814	2 200
Less capitalized costs related to major projects in progress	**(3 691)**	(2 497)	(1 084)	(373)	(599)
	2 230	2 232	2 363	2 441	1 601
Ratios					
Per common share (dollars)					
– net earnings attributable to common shareholders	**1.63**	1.58	0.74	0.81	0.98
– cash dividends	**0.34**	0.34	0.34	0.34	0.34
– cash flow provided from operations	**3.73**	4.32	2.68	2.64	2.62
– cash flow provided from operations attributable to common shareholders	**3.52**	4.11	2.51	2.64	2.62
Return on capital employed (%)*	**17.9**	16.6	8.3	9.5	14.3
Return on shareholders' equity (%)*	**14.8**	16.5	10.3	12.3	16.2
Debt to debt plus shareholders' equity (%)	**53.1**	47.7	38.9	46.7	36.8
Debt to cash flow provided from operations (times)	**3.8**	2.3	2.3	2.2	1.4
Interest coverage – cash flow basis*	**5.9**	9.0	9.1	8.7	15.4
Interest coverage – net earnings basis*	**3.7**	5.6	5.1	4.8	9.2

* Definitions

Capital employed – see page 52.

Return on shareholders' equity – earnings as a percentage of average shareholders' equity. Average shareholders' equity is the aggregate of total shareholders' equity at the beginning and end of the year divided by two.

Interest coverage – cash flow basis – cash provided from operations before interest expense and current income tax provision, divided by interest expense plus interest capitalized.

Interest coverage – net earnings basis – net earnings before interest expense and income tax payments, divided by interest expense plus interest capitalized.

supplemental financial and operating information

(unaudited)

	2001	2000	1999	1998	1997
OIL SANDS					
Production (thousands of barrels per day)	**123.2**	113.9	105.6	93.6	79.4
Sales (thousands of barrels per day)					
Light sweet crude oil	**56.2**	64.3	52.7	58.8	53.5
Diesel	**14.8**	9.3	8.2	9.7	10.0
Light sour crude oil	**42.0**	35.8	37.5	26.6	14.6
Bitumen	**8.5**	6.2	3.8	—	—
	121.5	115.6	102.2	95.1	78.1
Average sales price (dollars per barrel)					
Light sweet crude oil	**34.17**	35.31	26.06	22.80	26.65
Other (diesel, light sour crude oil and bitumen)	**24.86**	27.09	21.48	21.16	25.74
Total	**29.17**	31.67	23.84	22.18	26.36
Total*	**34.21**	41.29	25.89	20.37	27.98
Cash operating costs (dollars per barrel rounded to the nearest $0.05)**	**17.00**	13.55	11.70	11.75	13.25
Total operating costs (dollars per barrel rounded to the nearest $0.05)**	**19.60**	17.25	15.05	14.00	15.80
Other Oil Sands statistics					
Overburden removed (millions of cubic metres)	**50.9**	30.7	22.5	22.2	17.5
Oil sands mined (millions of tonnes)	**97.9**	84.9	72.9	62.4	54.1
Average bitumen content of oil sands mined (per cent by weight)	**10.4**	11.1	11.6	11.6	12.7
Average crude yield of oil sands mined (barrels per tonne)	**.459**	.491	.529	.547	.535

* Excludes the impact of hedging activities.

** See definitions on page 70.

Synthetic Crude Oil and Bitumen Gross Reserves*

(millions of barrels)	Mining Reserves Synthetic Crude Oil Proved	Mining Reserves Synthetic Crude Oil Probable	Total	Firebag In-situ Bitumen Probable	Total Proved and Probable
December 31, 1997	338	463	801	—	801
December 31, 1998	302	464	766	—	766
Revisions	(10)	(13)	(23)	—	(23)
Additions	222	1 577	1 799	—	1 799
Production	(38)	—	(38)	—	(38)
December 31, 1999	476	2 028	2 504	—	2 504
Revisions	(13)	6	(7)	—	(7)
Production	(41)	—	(41)	—	(41)
December 31, 2000	422	2 034	2 456	—	2 456
Revisions	(1)	(5)	(6)	—	(6)
Additions	—	—	—	2 029	2 029
Production	(45)	—	(45)	—	(45)
December 31, 2001	**376**	**2 029**	**2 405**	**2 029**	**4 434**

Gross proved reserves do not reflect deductions in respect of Crown and applicable sublease royalties. Under the Crown Royalty Agreement, the Crown royalty rate is dependent on deemed net revenues; therefore, calculations of the net reserves would vary depending upon assumed production rates, prices and operating and capital costs.

* Reserve estimates are based upon a detailed geological assessment, including drilling and laboratory analysis. Estimates also reflect the integrated nature of the operation and therefore reflect demonstrated productive capacity, upgrading yield, plans for increased output, operating life and regulatory constraints.

(unaudited)

	2001	2000	1999	1998	1997
NATURAL GAS					
Production					
Conventional					
Natural gas (millions of cubic feet per day)					
– gross	**177**	200	226	247	240
– net	**124**	142	170	195	199
Natural gas liquids (thousands of barrels per day)					
– gross	**2.4**	3.0	4.2	4.9	5.0
– net	**1.7**	2.1	3.0	3.7	3.5
Crude oil (thousands of barrels per day)					
– gross	**1.5**	4.2	9.2	11.4	10.7
– net	**1.1**	3.3	7.5	9.4	8.6
Total (thousands of boe* per day)					
– gross	**33.4**	40.5	51.1	57.5	55.7
– net	**23.5**	29.1	38.8	45.6	45.3
Average sales price					
Natural gas (dollars per thousand cubic feet)	**6.09**	4.72	2.44	1.95	1.93
Natural gas (dollars per thousand cubic feet)**	**6.12**	4.73	2.48	1.95	1.94
Natural gas liquids (dollars per barrel)	**34.38**	36.66	19.32	15.13	22.45
Crude oil					
– conventional (dollars per barrel)	**33.92**	29.50	20.94	20.14	22.75
– conventional (dollars per barrel)**	**38.14**	39.80	24.01	17.37	24.80
Undeveloped landholdings***					
Oil and gas (millions of acres)					
– western provinces					
– gross	**0.6**	1.4	1.5	1.7	1.7
– net	**0.5**	1.1	1.2	1.3	1.3
– international					
– gross	**1.7**	1.3	—	—	—
– net	**1.3**	1.1	—	—	—
Net wells drilled*****					
Conventional					
Exploratory – oil	**—**	—	1	2	7
– gas	**4**	1	5	10	10
– dry	**16**	15	13	18	25
Development – oil	**—**	2	2	15	26
– gas	**16**	14	4	16	10
– dry	**2**	3	1	8	4
	38	35	26	69	82

* Barrel of oil equivalent (boe) converts gas to oil on the approximate long-term economic equivalent basis that 6,000 cubic feet equals one barrel of oil.

** Excludes the impact of hedging activities.

*** Metric conversion: Landholdings – 1 hectare = approximately 2.5 acres.

**** Excludes interests in 14 net exploratory wells and seven net development wells in progress at the end of 2001.

Oil and Gas Data

The following supplemental oil and gas disclosure is provided in accordance with the provisions of the United States Statement of Financial Accounting Standards (SFAS) No. 69. This statement requires disclosure about conventional oil and gas activities only, and therefore the company's oil sands activities are excluded. Additional information required by SFAS No. 69 is included in the company's Form 40-F report, which is filed in the Electronic Data Gathering, Analysis and Retrieval (EDGAR) system of the United States Securities and Exchange Commission (SEC). This information can be accessed on the internet at www.freeedgar.com.

(unaudited)

Reserves	Gross		Net	
	Crude Oil and Natural Gas Liquids (millions of barrels)	Natural Gas (billions of cubic feet)	Crude Oil and Natural Gas Liquids (millions of barrels)	Natural Gas (billions of cubic feet)
Proved				
December 31, 1997	70	1 088	56	850
December 31, 1998	69	1 197	56	915
Revisions of previous estimates	(2)	(103)	(2)	(80)
Purchases of minerals in place	—	1	—	1
Extensions and discoveries	—	53	—	41
Production	(5)	(82)	(4)	(68)
Sales of minerals in place	(11)	(53)	(9)	(45)
December 31, 1999	51	1 013	41	764
Revisions of previous estimates	(3)	(52)	(6)	(81)
Purchases of minerals in place	—	9	—	7
Extensions and discoveries	1	39	1	28
Production	(3)	(73)	(2)	(52)
Sales of minerals in place	(30)	(139)	(23)	(99)
December 31, 2000	16	797	11	567
Revisions of previous estimates	(1)	(3)	—	4
Extensions and discoveries	—	27	—	20
Production	(1)	(65)	(1)	(45)
Sales of minerals in place	—	(1)	—	(1)
December 31, 2001	**14**	**755**	**10**	**545**
Proved developed				
December 31, 1997	55	727	44	568
December 31, 1998	53	730	43	557
December 31, 1999	38	627	30	471
December 31, 2000	13	573	10	414
December 31, 2001	**11**	**573**	**8**	**416**

Proved reserves are considered recoverable under current technology and existing economic conditions, from reservoirs that are evaluated on known drilling, geological, geophysical and engineering data.

Proved developed reserves are on production, or reserves that could be recovered from existing wells or facilities, if the company placed them on production.

Gross reserves are before deducting royalties. Net reserves are after deducting royalties. Royalties can vary depending upon factors such as prices, production volumes, timing of initial production and changes in legislation.

All reserves are located in Canada. There has been no major discovery or other favourable or adverse event which caused a significant change in estimated proved reserves since December 31, 2001. The company has no long-term supply agreements or contracts with governments or authorities in which it acts as producer nor does it have any interest in oil and gas operations accounted for by the equity method.

Standardized Measure of Discounted Future Net Cash Flows from Estimated Production of Proved Oil and Gas Reserves after Income Taxes

($ millions)	**2001**	2000	1999
At December 31	**440**	1 933	749

(unaudited)

	2001	2000	1999	1998	1997
SUNOCO					
Refined product sales (thousands of cubic metres per day)					
Transportation fuels					
Gasoline – retail*	**4.3**	4.2	4.1	4.1	3.8
– other	**4.4**	4.0	3.7	3.5	3.3
Jet fuel	**0.7**	1.1	1.1	1.0	1.2
Diesel	**3.1**	3.1	2.7	2.5	2.6
	12.5	12.4	11.6	11.1	10.9
Petrochemicals	**0.5**	0.6	0.7	0.7	0.7
Heating oils	**0.4**	0.4	0.4	0.6	1.0
Heavy fuel oils	**0.8**	0.6	0.5	0.7	0.7
Other	**0.6**	0.6	0.6	0.7	0.9
	14.8	14.6	13.8	13.8	14.2
Natural gas sales (millions of cubic feet per day)	**95**	83	89	88	14
Margins (cents per litre)					
Refining	**5.7**	5.9	4.0	4.1	4.6
Retail	**6.6**	6.6	7.4	7.0	6.8
Crude oil supply and refining					
Processed at Suncor Energy refinery (thousands of cubic metres per day)	**10.2**	10.9	10.6	11.0	10.8
Utilization of refining capacity (%)	**92**	98	95	99	97
Retail outlets** (number at year-end)	**400**	402	415	423	441

* Excludes sales through joint venture interests.

** Sunoco-branded service stations, other private brands managed by Sunoco and Sunoco's interest in service stations managed through joint ventures. Outlets are located mainly in Ontario.

	2001	2000	1999	1998	1997
TOTAL SUNCOR EMPLOYEES (number at year-end)	**3 307**	3 043	2 796	2 659	2 439

share trading information

(unaudited)
(Stock trading symbol SU)

The following share trading information reflects a two-for-one split of the company's common shares during 2000.

	For the Quarter Ended				For the Quarter Ended			
	Mar 31 2001	**June 30 2001**	**Sept 30 2001**	**Dec 31 2001**	Mar 31 2000	June 30 2000	Sept 30 2000	Dec 31 2000
Share ownership								
Average number outstanding, weighted monthly (thousands) (1)	**222 115**	**222 463**	**222 631**	**222 910**	221 064	221 265	221 562	221 773
Share price (dollars) (2)								
Toronto Stock Exchange								
High	**44.40**	**44.25**	**48.20**	**53.70**	34.95	36.90	39.80	38.80
Low	**31.70**	**37.05**	**38.05**	**41.50**	27.25	31.20	30.50	29.40
Close	**40.55**	**38.60**	**44.00**	**52.40**	31.45	34.20	33.20	38.30
New York Stock Exchange – US$								
High	**28.60**	**30.00**	**30.25**	**33.60**	22.00	24.95	26.75	26.40
Low	**21.00**	**24.35**	**25.00**	**26.10**	18.50	20.80	20.50	19.40
Close	**25.90**	**25.70**	**27.90**	**32.90**	21.25	23.25	22.15	25.70
Shares traded (thousands)								
Toronto Stock Exchange	**45 160**	**50 115**	**38 514**	**50 206**	42 976	32 903	37 181	43 177
New York Stock Exchange	**3 539**	**6 379**	**6 669**	**6 943**	3 014	3 268	2 371	2 851
Per common share information (dollars)								
Net earnings attributable to common shareholders	**0.53**	**0.71**	**0.30**	**0.09**	0.45	0.47	0.19	0.47
Cash dividends	**0.085**	**0.085**	**0.085**	**0.085**	0.085	0.085	0.085	0.085

(1) The company had approximately 1,225 holders of record of common shares as at January 31, 2002.

(2) The company's common shares are traded on the Toronto and New York stock exchanges.

Information for Security Holders Outside Canada
Cash dividends paid to shareholders resident in countries with which Canada has an income tax convention are usually subject to Canadian non-resident withholding tax of 15%. The withholding tax rate is reduced to 5% on dividends paid to a corporation if it is a resident of the United States that owns at least 10% of the voting shares of the company.

investor information

Stock Trading Symbols and Exchange Listing

Common shares (SU) are listed on the Toronto and New York stock exchanges. Suncor's 9.05% preferred securities (SU.PR.A-T) are listed on the Toronto Stock Exchange. Suncor's 9.125% preferred securities (SU.PR.A-N) are listed on the New York Stock Exchange.

Dividends

Suncor's Board of Directors reviews its dividend policy from time to time. In 2001, an aggregate dividend of $0.34 per share was paid.

Dividend Reinvestment and Common Share Purchase Plan

Suncor's Dividend Reinvestment and Common Share Purchase plan provides an efficient and cost-effective way for shareholders to increase their investment in the company. The plan enables resident Canadian and U.S. shareholders to invest cash dividends in common shares or acquire additional shares through optional cash payments without payment of brokerage commissions, service charges or other costs associated with administration of the plan. To obtain additional information, please call Computershare Trust Company of Canada at 1-888-267-6555.

Stock Transfer Agent and Registrar

In Canada, Suncor's agent is Computershare Trust Company of Canada with locations in Calgary, Edmonton, Toronto, Montreal and Vancouver. In the United States, Computershare Trust Company, Inc. is located in Denver, Colorado.

Account Management

Sometimes shareholders receive more than one copy of Suncor's Annual Report because their shares are registered under different names or addresses. If you receive but do not require more than one mailing, call Computershare Trust Company of Canada at 1-888-267-6555 to make arrangements to combine your accounts.

Annual Meeting

Suncor's annual and special meeting of shareholders will be held at 10 a.m. MST on April 26, 2002, at the Keyano College Theatre in Fort McMurray, Alberta. Presentations from the meeting will be web cast at www.suncor.com.

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Additional Information

In addition to annual and quarterly reports, Suncor publishes a bi-annual Report on Sustainability. To order copies of Suncor's print materials call 1-800-558-9071. More information about Suncor and print materials that can be downloaded are available from www.suncor.com.

La version française du rapport annuel de Suncor et de son rapport de durabilité peut être téléchargée à l'adresse suivante : www.suncor.com

corporate directors and officers

Officers

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Vice President, Finance

M. (Mike) Ashar
Executive Vice President, Oil Sands

David W. Byler
Executive Vice President,
Natural Gas and Renewable Energy

Richard L. George
President and Chief Executive Officer

Terrence J. Hopwood
Senior Vice President and General Counsel

Sue Lee
Senior Vice President,
Human Resources and Communications

Kevin D. Nabholz
Senior Vice President, Major Projects

Michael W. O'Brien
Executive Vice President, Corporate Development
and Chief Financial Officer

Janice B. Odegaard
Vice President, Associate General Counsel
and Corporate Secretary

Thomas L. Ryley
Executive Vice President,
Energy Marketing and Refining

JR Shaw
Chairman of the Board

Directors

Mel E. Benson [1,4]
Calgary, Alberta
Management Consultant
Director since 2000

Brian A. Canfield [3,4]
Point Roberts, Washington
Chairman, TELUS Corporation
Director since 1995
Chair, Human Resources
and Compensation Committee

Bryan P. Davies [1,4]
Toronto, Ontario
Senior Vice President, Regulatory Affairs
Royal Bank of Canada
Director since 2000

John T. Ferguson [1,2]
Edmonton, Alberta
Chairman, Princeton Development Ltd.
Chairman, TransAlta Corporation
Director since 1995

Richard L. George [2]
Calgary, Alberta
President and Chief Executive Officer
Suncor Energy Inc.
Director since 1991

Poul Hansen [1,4,5]
Vancouver, British Columbia
Chairman and General Manager
Sperling Hansen Associates Inc.
Director since 1996

John R. Huff [2,3]
Houston, Texas
Chairman and Chief Executive Officer
Oceaneering International, Inc.
Director since 1998

Robert W. Korthals [1,2]
Toronto, Ontario
Director since 1996
Chair, Audit Committee

M. Ann McCaig [3,4]
Calgary, Alberta
President, VPI Investments Ltd.
Director since 1995
Chair, Environment, Health and Safety Committee

JR Shaw [2,3]
Calgary, Alberta
Executive Chair, Shaw Communications Inc.
Chairman of the Board, Suncor Energy Inc.
Director since 1998
Chair, Board Policy, Strategy Review
and Governance Committee

W. Robert Wyman [2,3,5]
Vancouver, British Columbia
Director since 1987

1 Audit Committee
2 Board Policy, Strategy Review and Governance Committee
3 Human Resources and Compensation Committee
4 Environment, Health and Safety Committee
5 Retiring in April 2002

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